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DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 21

[Docket No. FAA–2010–0218; Amdt. No. 21–95]

RIN 2120–AJ56

Function and Reliability Flight Testing for Turbine-Powered Airplanes Weighing 6,000 Pounds or Less

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is revising the applicability of the function and reliability flight testing requirements to include all part 23 turbine-powered airplanes weighing 6,000 pounds or less. Revising the applicability is necessary because advancements in aviation technology have invalidated the reasons for excluding these airplanes. This revision is intended to improve aviation safety for these airplanes.

DATES: This rule becomes effective December 19, 2011.

FOR FURTHER INFORMATION CONTACT: Victor Powell, Aircraft Certification Service, Aircraft Engineering Division, Certification Procedures Branch, AIR–110, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; *telephone:* (202) 385–6326; *e-mail: victor.powell@faa.gov.*

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The Federal Aviation Administration's (FAA) authority to issue rules on aviation safety is found in Title 49 of the United States Code. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes the scope of the FAA Administrator's authority.

This rulemaking is promulgated under the authority described in subtitle VII, part A, subpart III, chapter 447, section 44701. Under that section, Congress charges the FAA with promoting the safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the FAA Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it will prescribe new flight test requirements for certain turbine-powered airplanes.

I. Background

This rulemaking will only change the applicability portion of Title 14, Code of Federal Regulations (14 CFR), 21.35(b)(2) by removing the 6,000 pound weight exclusion for part 23 turbine-powered airplanes because of advancements in technology, as discussed in the notice of proposed rulemaking (NPRM). This rulemaking does not change existing function and reliability (F & R) flight testing requirements in § 21.35.

The FAA issued ''Proposed Notification Regarding Function and Reliability Testing for Turbofan-Powered Airplanes of 6,000 Pounds or Less Maximum Certificated Weight.'' (*See* 69 FR 5239, February 3, 2004.) In that notice, we announced our intention to require F & R flight testing by special conditions for future part 23 type certification (TC) projects. Eclipse Aviation Corporation (Eclipse) was excluded from the proposal as an ongoing TC project. We issued special conditions requiring F & R flight testing for the Cirrus Design Corporation Model SF50 airplane. (*See* 75 FR 50853, August 18, 2010.) This final rule will eliminate the need for issuing special conditions for F & R flight testing.

A. Statement of the Problem

Function and reliability flight testing is required by § 21.35(b)(2) for all airplanes weighing more than 6,000 pounds maximum certificated weight that are to be certificated under part 23. Function and reliability flight testing is not required for gliders, nor for part 23 airplanes weighing 6,000 pounds or less. Because of advancements in airplane structures, propulsion methods, and systems technologies, the 6,000-pound demarcation is no longer justified. Part 23 turbine-powered airplanes that weigh 6,000 pounds or less currently are not required to undergo F & R flight testing regardless of the airplane's systems complexity or level of automation.

After reviewing several recent proposed type certification projects for small turbojet-powered airplanes—involving airplanes expected to weigh 6,000 pounds or less—the FAA has determined that most, if not all, of these airplane designs will benefit from the F & R flight testing requirement. This determination is based on new lightweight turbine-powered airplanes having design features and performance consistent with larger airplanes that are required to undergo F & R flight testing.

B. Summary of the NPRM

The technological advancements in new airplane designs and their high-performance potential prompted the FAA to publish in the **Federal Register** the NPRM entitled ''Function and Reliability Flight Testing for Turbine-Powered Airplanes Weighing 6,000 Pounds or Less.'' (*See* 75 FR 18134, April 9, 2010.) In that NPRM, we proposed changes to the applicability of F & R flight testing procedures for part 23 airplanes. In general, we proposed to expand the applicability of F & R flight testing requirements to all part 23 turbine-powered airplanes that weigh 6,000 pounds or less to be certificated under part 23. However, the exception for gliders and reciprocating-engine powered airplanes weighing 6,000 pounds or less that are type certificated under part 23 will remain.

The original decision to exclude certain airplanes weighing 6,000 pounds or less from F & R flight testing was based on the state of technology existing in 1950. At that time, airplanes weighing 6,000 pounds or less were expected to be used mainly as personal airplanes. Such civil airplanes developed between the years of 1945 and 1955 were typically single, reciprocating-engine powered airplanes weighing 3,000 pounds or less with engine output of less than 300 horsepower. Technological advancements now allow airplanes that weigh 6,000 pounds or less to be more complex and automated than some transport category airplanes of the 1960s and earlier. The NPRM contains more of the historical background and reasons

for this final rule. You should refer to the NPRM for that information.

C. Summary of the Comments

We received nine substantive comments from five commenters. Commenters to the NPRM represented manufacturers of airplanes and airplane engines, and other individuals. We also received comments from an aviation consulting group. The commenters generally had concerns about changes to F & R flight testing criteria and supplied alternative recommendations as discussed more fully in the Discussion of the Final Rule below. The comment period for the NPRM closed on July 8, 2010.

In general, the FAA received comments on the following areas of the proposal:

- Using the experience of the aircraft manufacturer cited in the NPRM.
- Basing the applicability of F & R flight testing on turbine-powered airplanes instead of other criteria, such as complexity.
- The safety benefits versus the costs to perform F & R flight testing for part 23 turbine-powered airplanes weighing 6,000 pounds or less.

II. Discussion of the Final Rule

Again, this final rule will only change the applicability of § 21.35(b)(2) by removing the 6,000 pound weight exclusion for part 23 turbine-powered airplanes because of advancements in technology, as discussed in the notice of proposed rulemaking (NPRM). This final rule does not change existing F & R flight testing requirements.

Aero-Cert stated that relying on the experience of the aircraft manufacturer cited in the NPRM is flawed. Aero-Cert was concerned the proposed rule was based on the Eclipse EA–500 certification experience and objected to it being referenced in the NPRM. The individual commenter suggested that proper oversight during the design approval process is the best way to address
F & R flight testing. The individual commenter also stated that the problems encountered by an inexperienced applicant would not happen with an experienced design organization.

The FAA acknowledges that proper oversight is a primary objective in the design approval process. However, we are only changing the applicability of § 21.35. Function and reliability flight testing is envisioned for the design of new model airplanes and their systems. The level of expertise of the applicant is not a factor in the requirement.

The Eclipse certification experience showed that a manufacturer could type certificate a very light jet below the 6,000 pound threshold. The NPRM addressed the reality that advancements in technology since 1950 have led to the manufacture of high-performance, part 23 airplanes—those weighing 6,000 pounds or less—with complex systems. Therefore, the reliability of in-flight operations for those airplanes must be assessed before issuance of the type certificate.

Aero-Cert and the individual commenter further stated that basing the F & R flight testing requirements on the type of powerplant is flawed. They believed the issues that should drive the need for F & R flight testing are related to performance and the kinds of operations in which the airplane will be used, not the type of powerplant.

The FAA notes that F & R flight testing is required for all covered airplanes and should cover the normal operating environment in which an airplane will be used. Because of difficulty in choosing the type of testing based on the kinds of aircraft operation or the type of powerplant, the FAA chose to retain the existing provisions and has expanded the requirement to include the newer designs (such as very light jets and turbopropeller-driven airplanes) that are, by weight, presently excluded from F & R flight testing.

Cessna and the individual commenter stated the rulemaking would impose a cost burden on manufacturers not justified by the benefits. In the words of Cessna, ''* * * the proposed NPRM has the potential to *impose burden upon the manufacturer not commensurate with safety gained.* For example, if a simple, well-developed airplane were modified with a reliable, well-developed turbine engine, it is not likely that F & R [flight] testing would discover issues not encountered during properly conducted certification testing. In this case, the 150-hour F & R [flight] testing proposed by the NPRM would be an undue [cost] burden on the manufacturer or the STC [supplemental type certificate] holder.'' Also, the individual commenter stated that these costs would reduce the competitiveness of American-made aircraft and give foreign aircraft manufacturers an unfair advantage.

The FAA notes that the commenters did not include any analysis or data to show that costs imposed by the rule would impose costs not equal to safety gained. The FAA has determined that the expected costs of the rule are modest in comparison to the expected benefits. We estimate that benefits will be at least three to six times the expected costs, depending on the engines chosen. (*See* § 21.35(f).)

The rule addresses applicability only and does not change the minimum number of hours required by § 21.35(f) (that is, 150 or 300 hours, whichever is appropriate). Some simultaneous flight testing performed as part of the certification process may also be counted toward F & R flight testing if the conditions of § 21.35(a) are met at the time the testing is performed (for example, testing related to Type Inspection Authorization). Given the cost-beneficial nature of the rule for the case of a newly type-certificated airplane with an engine previously used on a type-certificated airplane, we believe the rule will remain substantially cost-beneficial.

The FAA has also found no evidence that American-made aircraft would be at a disadvantage in comparison to foreign-made aircraft as a result of this rule. Due to global harmonization efforts, the European Aviation Safety Agency (EASA) and other foreign airworthiness authorities have similar requirements for certification, including F & R flight testing requirements.

Rolls Royce stated that the use of the word ''turbine,'' which was proposed in the NPRM, should be better defined. The commenter asked the FAA to revise the proposed rule, so that turbopropeller-driven (turboprop) aircraft would not be affected by the final rule, and submitted proposed language to that effect. However, we did not revise the rule (§ 21.35) to limit its applicability to only airplanes having turbofan-powered (turbofan) or turbojet-powered (turbojet) engines. This decision is consistent with other FAA plans for part 23 rule changes discussed in the part 23 ''Certification of Turbojets'' NPRM. (*See* 74 FR 41522, August 17, 2009.) Those decisions point out that features affecting the complexity of airplane operating systems are not limited to powerplant features.

In addition, Cessna stated that the evaluation of F & R flight testing (if needed) should be based on the scope of the project, such as the number of complex integrated systems, and that guidance should be developed accordingly.

While the FAA agrees that the use of complexity criteria might be an appropriate method to evaluate F & R flight testing, the FAA notes that the scope of the project, or the number of complex systems, may not be the most efficient measure for requiring this testing. The FAA also notes that obtaining agreement on what constitutes a complex integrated system that could be placed within part 21 regulations would be a difficult and burdensome

task. It would also delay adding already identified airplanes to the safety assessment of F & R flight testing. The FAA has also determined that defining complex systems may have implications beyond F & R flight testing, such as for pilot training requirements and flight operations.

IV. Regulatory Notices and Analyses

Paperwork Reduction Act

The Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3507(d)) requires that the FAA consider the impact of paperwork and other information collection burdens imposed on the public. We have determined that there is no information collection burden associated with this final rule.

International Compatibility

In keeping with U.S. obligations under the Convention on International Civil Aviation, it is FAA policy to comply with International Civil Aviation Organization (ICAO) Standards and Recommended Practices to the maximum extent practicable. The FAA has reviewed the corresponding ICAO Standards and Recommended Practices and has identified no differences with these regulations.

Final Regulatory Evaluation, Regulatory Flexibility Determination, International Trade Impact Assessment, and Unfunded Mandates Assessment

Changes to Federal regulations must undergo several economic analyses. First, Executive Order 12866 directs that each Federal agency shall propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs. Second, the Regulatory Flexibility Act of 1980 (Pub. L. 96–354) requires agencies to analyze the economic impact of regulatory changes on small entities. Third, the Trade Agreements Act (Pub. L. 96–39) prohibits agencies from setting standards that create unnecessary obstacles to the foreign commerce of the United States. In developing U.S. standards, this Trade Act requires agencies to consider international standards and, where appropriate, that they be the basis of U.S. standards. Fourth, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a federal mandate likely to result in the expenditure by state, local, or tribal governments, in the aggregate, or by the private sector, of $100 million or more annually (adjusted for inflation with base year of 1995). This portion of the preamble summarizes the FAA's analysis of the economic impacts of this final rule. We suggest readers seeking greater detail read the full regulatory evaluation, a copy of which we have placed in the docket for this rulemaking.

In conducting these analyses, FAA has determined that this final rule: (1) Has benefits that justify its costs, (2) is not an economically ''significant regulatory action'' as defined in section 3(f) of Executive Order 12866, (3) is not ''significant'' as defined in the DOT's Regulatory Policies and Procedures; (4) will not have a significant economic impact on a substantial number of small entities; (5) will not create unnecessary obstacles to the foreign commerce of the United States; and (6) will not impose an unfunded mandate on state, local, or tribal governments, or on the private sector by exceeding the threshold identified above. These analyses are summarized below.

Total Costs and Benefits of This Final Rule

We expect that the typical certification project for an airplane subject to the final rule will be for a new airplane design with a turbine engine type previously used in a type-certificated aircraft requiring 165 hours [1] of F & R flight testing at a total cost of about $317,000. In the case of new airplane design and an engine type not previously used on a type-certificated airplane, we estimate that double the hours (330) will be required, so the total cost will double to $634,000. We expect that this final rule will enhance safety and reduce costs by substantially reducing the number of safety incidents and Airworthiness Directives experienced post-certification. A partial estimate of the expected costs that will be avoided for a single new airplane design amounts to $1.8 million, with a present value of $1.6 million. These avoided costs are approximately six times the costs of our 165-hour ''typical'' estimate and approximately triple the higher 330-hour estimate. Consequently, the expected benefits of this final rule greatly exceed its modest expected costs.

Who is affected by this rule?

Manufacturers of part 23 turbine-powered airplanes weighing 6,000 pounds or less are affected.

Assumptions and Sources of Information

- We use a two-year period of analysis, as we find this period sufficient to show the cost-beneficial nature of this final rule. We use the period from the beginning of 2007 to the end of 2008, as the data used in the analysis are from this period. The short period of analysis reflects the inherent nature of F & R flight testing, designed as it is to uncover design or system reliability flaws that otherwise would reveal themselves in the very early life of an airplane.
- Discount rate is 7% (Office of Management and Budget, Circular A–94, ''Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs,'' October 29, 1992, p. 8).
- Data on costs of compliance with this rule were obtained from a part 23 airplane manufacturer and FAA estimates.

Costs of This Final Rule

We estimate the costs of this final rule based on the F & R costs incurred by a part 23 airplane manufacturer for a turbojet-powered airplane (turbojet) with a maximum weight greater than 6,000 pounds. The turbine-powered Eclipse EA–500, with a maximum weight less than 6,000 pounds, was recently type certificated under a program in which it voluntarily undertook a reduced 200-hour F & R flight testing program, 100 hours pre-certification and 100 hours post-certification.[2] The F & R flight testing costs for the Eclipse EA–500 would be difficult, if not impossible, to obtain because Eclipse Aviation Corporation has been liquidated under Chapter 7 bankruptcy and a new firm, Eclipse Aerospace, has been formed to take over its assets. We believe our use of more readily obtainable data for a part 23 turbojet weighing somewhat more than 6,000 pounds is adequate. Moreover, as we will see below, the *ad hoc* nature of Eclipse's voluntary F & R flight testing program appears to have limited the appropriateness of the Eclipse F & R flight testing cost data, even if available. We may overestimate the cost of F & R flight testing by our use of costs for an airplane weighing more than airplanes affected by this final rule.

We estimate F & R flight testing cost per hour in order to more easily incorporate different estimates of total F & R flight testing hours. Test pilot and flight test engineer costs are FAA estimates. All other cost estimates were

[1] See the separate cost section below for the reason we increased the number of hours from 150 (the minimum required by § 21.35(f)) to 165.

[2] Pratt & Whitney Canada developed a new PW610F engine for the Eclipse EA–500.

provided by a part 23 airplane manufacturer.

For aircraft subject to F & R flight testing under 14 CFR 21.35(b)(2), 21.35(f) requires at least 300 hours of F & R flight testing ''with a full complement of engines'' for aircraft ''incorporating turbine engines of a type not previously used in a type certificated aircraft,'' and at least 150 hours for all other aircraft. As most proposed very light jet (VLJ) type certification projects appear to be based on the type-certificated Williams FJ–33 engine or other previously type-certificated engines, we expect this minimum requirement to hold for the typical project subject to this final rule.

Function and reliability flight testing for 150 hours was required for the airplane's data we use here, so one of our cost estimates assumes 150 hours of F & R flight testing. Sometimes, to fulfill the requirements of F & R flight testing, more than the minimum number of flight hours is necessary. For the purposes of this cost analysis, we used an average extension of 10%, or 15 hours, so our ''typical'' estimate assumes 165 hours of F & R flight testing. We double that estimate to also provide an estimate for a new airplane design with a new engine design.

Benefits of This Final Rule

We expect that adoption of this final rule will enhance safety and reduce costs by substantially reducing the number of service difficulties experienced post-certification. This expectation is supported by evidence from the service experience of the Eclipse EA–500. The Eclipse Special Certification Review [3] (Eclipse SCR) team looked at 85 Eclipse Service Difficulty Reports (SDRs) submitted between July 29, 2007 and May 13, 2008 and ''concluded the majority of the SDRs resulted from reliability issues separate from compliance with the minimum FAA standards.'' (*See* Eclipse SCR, Executive Summary.) There also were six Eclipse-related ADs issued in the one-year period between November 2007 and November 2008. Eclipse voluntarily conducted its own limited F & R flight testing. However, the FAA team did not view F & R flight testing as a requirement for Eclipse to receive its type certificate. (*See* Eclipse SCR, p. 28.) This deficiency in Eclipse's volunteer F & R flight testing program provides direct empirical evidence for the benefits of F & R flight testing.

The FAA estimates that the pitot/angle of attack (AOA) issue (AD 2008–02–04; SCR, p. 25) is the one most likely to have been uncovered by a mandatory F & R flight testing program. Extending the AD estimate to the entire U.S.-registered Eclipse EA–500 fleet (264 airplanes), we estimate the total cost of the pitot/AOA problem to be $2.5 million. However, we assess the probability of F & R flight testing uncovering the pitot/AOA problem to be approximately 0.7 to 0.75. Using the lower figure, we accordingly calculate the expected benefit as the total cost avoided of $2.5 million times 0.7, or $1.8 million. (We received no comment on this same method of calculating rule benefits used in the NPRM.) Since the FAA issued a type certificate on September 30, 2006, approximately 1.5 years prior to the compliance date for the Eclipse pitot/AOA AD, we discount the expected benefit 1.5 years to find present value benefit of $1.6 million.

Final Regulatory Flexibility Determination

The Regulatory Flexibility Act of 1980 (Pub. L. 96–354) (RFA) establishes ''as a principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation. To achieve this principle, agencies are required to solicit and consider flexible regulatory proposals and to explain the rationale for their actions to assure that such proposals are given serious consideration.'' The RFA covers a wide-range of small entities, including small businesses, not-for-profit organizations, and small governmental jurisdictions.

Agencies must perform a review to determine whether a rule will have a significant economic impact on a substantial number of small entities. If the agency determines that it will, the agency must prepare a regulatory flexibility analysis as described in the RFA. However, if an agency determines that a rule is not expected to have a significant economic impact on a substantial number of small entities, section 605(b) of the RFA provides that the head of the agency may so certify and a regulatory flexibility analysis is not required. The certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

The FAA has determined that this final rule will not have a significant impact on a substantial number of entities for the following reason: The cost of requiring F & R flight testing is a small one-time cost and a very small percentage of development, certification, and production costs. We received no comments on the same determination made in the NPRM. Therefore, as the FAA Administrator, I certify that this final rule will not have a significant economic impact on a substantial number of small entities.

International Trade Impact Assessment

The Trade Agreements Act of 1979 (Pub. L. 96–39) prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. Legitimate domestic objectives, such as safety, are not considered unnecessary obstacles. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards. The FAA has assessed the potential effect of this final rule and determined the purpose is to promote safety. This final rule is therefore not considered an unnecessary obstacle to foreign commerce of the United States.

Unfunded Mandates Assessment

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires each Federal agency to prepare a written statement assessing the effects of any Federal mandate in a proposed or final agency rule that may result in an expenditure of $100 million or more (adjusted annually for inflation with the base year 1995) in any one year by State, local, and tribal governments, in the aggregate, or by the private sector; such a mandate is deemed to be a ''significant regulatory action.'' The FAA currently uses an inflation-adjusted value of $143.1 million.

This final rule does not contain such a mandate. The requirements of Title II do not apply.

Executive Order 13132, Federalism

The FAA analyzed this final rule under the principles and criteria of Executive Order 13132, Federalism. We determined that this action will not have a substantial direct effect on the States, or the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, and, therefore, will not have federalism implications.

[3] Special Certification Review: Eclipse Aviation Corporation Model EA–500 Airplane. Prepared for the Federal Aviation Administration Associate Administrator for Aviation Safety, September 12, 2008.

Regulations Affecting Intrastate Aviation in Alaska

Section 1205 of the FAA Reauthorization Act of 1996 (110 Stat. 3213) requires the Administrator, when modifying regulations in Title 14 of the CFR in a manner affecting intrastate aviation in Alaska, to consider the extent to which Alaska is not served by transportation modes other than aviation, and to establish appropriate regulatory distinctions. The final rule would apply to the certification of all airplanes and are not specific to air transportation in Alaska.

Environmental Analysis

FAA Order 1050.1E identifies FAA actions that are categorically excluded from preparation of an environmental assessment or environmental impact statement under the National Environmental Policy Act in the absence of extraordinary circumstances. The FAA has determined this final rulemaking action qualifies for the categorical exclusion identified in paragraph 312(f) of the Order and involves no extraordinary circumstances.

Regulations That Significantly Affect Energy Supply, Distribution, or Use

The FAA has analyzed this final rule under Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use (May 18, 2001). We have determined that it is not a ''significant regulatory action'' under the executive order because it is not a ''significant regulatory action'' under Executive Order 12866, and it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

Availability of Rulemaking Documents

You can get an electronic copy of rulemaking documents using the Internet by—

1. Searching the Federal eRulemaking Portal (*http://www.regulations.gov*);

2. Visiting the FAA's Regulations and Policies Web page at *http://www.faa.gov/regulations_policies/* or

3. Accessing the Government Printing Office's Web page at *http://www.gpoaccess.gov/fr/index.html*.

You can also get a copy by sending a request to the Federal Aviation Administration, Office of Rulemaking, ARM–1, 800 Independence Avenue, SW., Washington, DC 20591, or by calling (202) 267–9680. Make sure to identify the notice, amendment, or docket number of this rulemaking.

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or by signing the comment, if submitted on behalf of an association, business, labor union, *etc.*). You may review DOT's complete Privacy Act statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78) or you may visit *http://DocketsInfo.dot.gov*.

Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996 requires FAA to comply with small entity requests for information or advice about compliance with statutes and regulations within its jurisdiction. If you are a small entity and you have a question regarding this document, you may contact your local FAA official, or the person listed under the **FOR FURTHER INFORMATION CONTACT** heading at the beginning of the preamble. You can find out more about SBREFA on the Internet at *http://www.faa.gov/regulations_policies/rulemaking/sbre_act/*.

List of Subjects in 14 CFR Part 21

Aircraft, Aviation safety, Exports, Imports, Reporting and recordkeeping requirements.

The Amendment

In consideration of the foregoing, the Federal Aviation Administration amends Chapter I of Title 14, Code of Federal Regulations, as follows:

PART 21—CERTIFICATION PROCEDURES FOR PRODUCTS AND PARTS

■ 1. The authority citation for part 21 continues to read as follows:

Authority: 42 U.S.C. 7572; 49 U.S.C. 106(g), 40105, 40113, 44701–44702, 44704, 44707, 44709, 44711, 44713, 44715, 45303.

■ 2. Amend § 21.35 by revising paragraph (b)(2) to read as follows:

§ 21.35 Flight tests.

* * * * *

(b) * * *

(2) For aircraft to be certificated under this subchapter, except gliders and except reciprocating engine powered airplanes of 6,000 lbs. or less maximum certificated weight that are to be certificated under part 23 of this chapter, to determine whether there is reasonable assurance that the aircraft, its components, and its equipment are reliable and function properly.

* * * * *

Issued in Washington, DC, on August 19, 2011.

J. Randolph Babbitt,

Administrator.

[FR Doc. 2011–26955 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket FAA No. FAA–2011–0439; Airspace Docket No. 11–ANM–10]

Amendment of Class D and Class E Airspace and Establishment of Class E Airspace; Casper, WY

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule; correction.

SUMMARY: This action corrects errors in the legal description of a final rule published in the **Federal Register** of August 25, 2011 that amends Class D and Class E airspace, and establishes Class E en route domestic airspace at Casper, WY.

DATES: *Effective Date:* 0901 UTC, October 20, 2011. The Director of the Federal Register approves this incorporation by reference action under 1 CFR part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

FOR FURTHER INFORMATION CONTACT: Eldon Taylor, Federal Aviation Administration, Operations Support Group, Western Service Center, 1601 Lind Avenue, SW., Renton, WA 98057; telephone (425) 203–4537.

SUPPLEMENTARY INFORMATION:

History

Federal Register Docket No. FAA–2011–0439, Airspace Docket No. 11–ANM–10, published on August 25, 2011 (76 FR 53048), amends Class D airspace, Class E surface airspace, Class E designated as an extension, and Class E airspace extending upward from 700 feet above the surface; and establishes Class E en route domestic airspace at Natrona County International Airport, Casper, WY. An error was made referencing the Victor airway in the regulatory text for Class E airspace extending upward from 700 feet above the surface. Also, in the Class E en route domestic airspace area, the portion referencing excluding existing controlled airspace 7,100 feet MSL and above is replaced with the correct wording. Class D and E airspace designations are published in paragraph 6005 and 6006, respectively, of FAA

Order 7400.9V dated August 9, 2011, and effective September 15, 2011, which is incorporated by reference in 14 CFR Part 71.1. The Class E airspace designations listed in this document will be published subsequently in that Order.

Correction to Final Rule

Accordingly, pursuant to the authority delegated to me, the Class E airspace descriptions as published in the **Federal Register** of August 25, 2011 (76 FR 53048) (FR Doc. 2011–21663) for Natrona County International Airport, Casper, WY, is corrected under the airspace designations as follows:

ANM WY E5 Casper WY [Corrected]

■ On page 53049, column 2, line 49 of the regulatory text, remove ''V–19'', and insert ''V–611''.

ANM WY E6 Casper, WY [Corrected]

■ On page 53049, column 2, line 61 of the regulatory text, remove ''excluding existing controlled airspace 7,100 feet MSL and above,'' and insert ''excluding existing lateral limits of controlled airspace 7,500 feet MSL and above''.

Issued in Seattle, Washington, on October 6, 2011.

John Warner,

Manager, Operations Support Group, Western Service Center.

[FR Doc. 2011–26732 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2011–0707; Airspace Docket No. 11–AEA–17]

Establishment of Class E Airspace; Palmyra, PA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes Class E airspace at Palmyra, PA, to accommodate new Area Navigation (RNAV) Global Positioning System (GPS) Standard Instrument Approach Procedures at Reigle Field. This action enhances the safety and management of Instrument Flight Rules (IFR) operations at the airport. This action also makes a minor adjustment to the geographic coordinates of the airport.

DATES: Effective 0901 UTC, December 15, 2011. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

History

On August 10, 2011, the FAA published in the **Federal Register** a notice of proposed rulemaking (NPRM) to amend Class E airspace 700 feet above the surface, at Palmyra, PA (76 FR 49390). Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. No comments were received. Subsequent to publication, the FAA found that the geographic coordinates needed to be adjusted; this rule makes that adjustment. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9V dated August 9, 2011, and effective September 15, 2011, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 amends Class E airspace extending upward from 700 feet above the surface to support new standard instrument approach procedures developed at Reigle Field, Palmyra, PA. This action also adjusts the geographic coordinates of the airport to be in concert with the FAAs aeronautical database. This enhances the safety and management of IFR operations at the airport. Except for the changes noted above, this action is the same as that proposed in the NPRM.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it establishes Class E airspace at Reigle Field, Palmyra, PA.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR Part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9V, Airspace Designations and Reporting Points, dated August 9, 2011, effective September 15, 2011, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

AEA PA E5 Palmyra, PA [New]

Reigle Field, PA

(Lat. 40°17′12″ N., long. 76°34′37″ W.)

That airspace extending upward from 700 feet above the surface within a 9.6-mile radius of Reigle Field.

Issued in College Park, Georgia, on October 5, 2011.

Barry A. Knight,

Acting Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–26467 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2011–0727; Airspace Docket No. 11–ASO–32]

Establishment of Class E Airspace; Nahunta, GA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes Class E Airspace at Nahunta, GA, to accommodate the new Area Navigation (RNAV) Global Positioning System (GPS) Standard Instrument Approach Procedures serving Brantley County Airport. This action enhances the safety and airspace management of Instrument Flight Rules (IFR) operations within the National Airspace System. This action also makes a minor adjustment to the geographic coordinates of the airport.

DATES: Effective 0901 UTC, December 15, 2011. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

History

On July 29,, 2011, the FAA published in the **Federal Register** a notice of proposed rulemaking to establish Class E airspace at Nahunta, GA (76 FR 45478) Docket No. FAA–2011–0727. Subsequent to publication, the FAA found a typographical error in the longitude coordinates. This action makes the correction. Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. No comments were received. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9V dated August 9, 2011, and effective September 15, 2011, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order. With the exception of editorial changes, and the changes described above, this rule is the same as that proposed in the NPRM.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 establishes the Class E airspace extending upward from 700 feet above the surface at Nahunta, GA, to provide the controlled airspace required to accommodate the new RNAV GPS Standard Instrument Approach Procedures developed for Brantley County Airport. This action is necessary for the safety and management of IFR operations at the airport. Also, the longitude coordinates of the airport are corrected from 'long. 81°54′10′22″ W to long. 81°54′22″.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it establishes controlled airspace at Brantley County Airport, Nahunta, GA.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR Part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9V, Airspace Designations and Reporting Points, dated August 9, 2011, effective September 15, 2011, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ASO GA E5 Nahunta, GA [New]

Brantley County Airport, GA
(Lat. 31°12′22″ N., long. 81°54′22″ W.)

That airspace extending upward from 700 feet above the surface within a 6.4-mile radius of the Brantley County Airport

Issued in College Park, Georgia, on October 4, 2011.

Mark D. Ward,

Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–26470 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2011–0102; Airspace Docket No. 11–ASO–39]

Amendment of Class E Airspace; Cleveland, MS

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends Class E Airspace at Cleveland, MS. The Renova Non-Directional Beacon (NDB) has been decommissioned and new Standard Instrument Approaches have been developed for Cleveland Municipal

Airport. This action enhances the safety and management of Instrument Flight Rules (IFR) operations at the airport.

DATES: Effective 0901 UTC, December 15, 2011. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

History

On July 25, 2011, the FAA published in the **Federal Register** a notice of proposed rulemaking to amend Class E airspace at Cleveland, MS, (76 FR 44286) Docket No. FAA–2011–0102. Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. No comments were received. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9V dated August 9, 2011, and effective September 15, 2011, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 amends Class E airspace extending upward from 700 feet above the surface at Cleveland, MS, to accommodate new standard instrument approach procedures developed for Cleveland Municipal Airport. The Renova NDB has been decommissioned, and the NDB approach cancelled, making this modification necessary for the safety and management of IFR operations within the National Airspace System.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore, (1) Is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it amends controlled airspace Cleveland Municipal Airport, Cleveland, MS.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR Part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9V, Airspace Designations and Reporting Points, dated August 9, 2011, effective September 15, 2011, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ASO MS E5 Cleveland, MS [Amended]

Cleveland Municipal Airport, MS
(Lat. 33°45′40″ N., long. 90°45′28″ W.)

That airspace extending upward from 700 feet above the surface within a 6.7-mile radius of the Cleveland Municipal Airport

Issued in College Park, Georgia, on October 4, 2011.

Mark D. Ward,

Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–26471 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2011–0380; Airspace Docket No. 11–AEA–12]

Establishment of Class E Airspace; New Market, VA

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action establishes Class E Airspace at New Market, VA, to accommodate the new Standard Instrument Approach Procedures serving New Market Airport. This action enhances the safety and airspace management of Instrument Flight Rules (IFR) operations within the National Airspace System. This action also makes a minor adjustment to the geographic coordinates of the airport.

DATES: Effective 0901 UTC, December 15, 2011. The Director of the Federal Register approves this incorporation by reference action under title 1, Code of Federal Regulations, part 51, subject to the annual revision of FAA Order 7400.9 and publication of conforming amendments.

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

History

On July 25, 2011, the FAA published in the **Federal Register** a notice of proposed rulemaking to establish Class E airspace at New Market, VA (76 FR 44288). Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal to the FAA. No comments were received. Subsequent to publication, the FAA found that the geographic coordinates needed to be adjusted; this rule makes that adjustment. Class E airspace designations are published in paragraph 6005 of FAA Order 7400.9V dated August 9, 2011, and effective September

15, 2011, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designations listed in this document will be published subsequently in the Order.

The Rule

This amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 establishes Class E airspace extending upward from 700 feet above the surface at New Market, VA, to provide the controlled airspace required to support the new RNAV GPS standard instrument approach procedures developed for New Market Airport. This action is necessary for the safety and management of IFR operations at the airport. This action also adjusts the geographic coordinates of the airport to be in concert with the FAA's aeronautical database.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current, is non-controversial and unlikely to result in adverse or negative comments. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it establishes controlled airspace at New Market Airport, New Market, VA.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR Part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9V, Airspace Designations and Reporting Points, dated August 9, 2011, effective September 15, 2011, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

AEA VA E5 New Market, VA [New]

New Market Airport, VA
(Lat. 38°39′22″ N., long. 78°42′31″ W.)

That airspace extending upward from 700 feet above the surface within a 14.8-mile radius of New Market Airport.

Issued in College Park, Georgia, on October 4, 2011.

Mark D. Ward,

Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–26469 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF LABOR

Wage and Hour Division

29 CFR Parts 500 to 899

Republication

CFR Correction

Title 29 of the Code of Federal Regulations, Parts 500 to 899, revised as of July 1, 2011, is being republished in its entirety. The earlier issuance inadvertently omitted footnotes 41 through 58, referenced in §§ 776.20 and 776.21. The omitted footnotes should appear on pages 368 through 371.

[FR Doc. 2011–26979 Filed 10–13–11; 5:19 pm]

BILLING CODE 4510–27–P

CENTRAL INTELLIGENCE AGENCY

32 CFR Part 1909

Access by Historical Researchers and Certain Former Government Personnel; Correction

AGENCY: Central Intelligence Agency.

ACTION: Final rule; correction.

SUMMARY: On September 23, 2011, the Central Intelligence Agency published a final rule resulting from a review of its public regulations on access by historical researchers and certain former government personnel. As a result of the review, the Agency has revised its access regulations to more clearly reflect the current CIA organizational structure and policies and practices, and to eliminate ambiguous, redundant and obsolete regulatory provisions. Due to a technical error in the review process, an amendment was worded inaccurately. This document corrects that error.

DATES: Effective October 18, 2011 and applicable beginning September 23, 2011.

FOR FURTHER INFORMATION CONTACT: Joseph W. Lambert, (703) 613–1379.

SUPPLEMENTARY INFORMATION: In FR Doc. No. 2011–21576 appearing on page 59034 in the **Federal Register** of September 23, 2011, the following correction is made:

§ 1909.14 [Corrected]

■ 1. On page 59035, in the third column, amendatory instruction 8 and § 1909.14 heading are revised to read as follows:

* * * * *

■ 8. Revise § 1909.14 to read as follows:

§ 1909.14. Determinations on requests for access by historical researchers.

* * * * *

Dated: October 11, 2011.

Joseph W. Lambert,

Director, Information Management Services.

[FR Doc. 2011–26901 Filed 10–17–11; 8:45 am]

BILLING CODE 6310–02–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2011–0491; EPA–R03–OAR–2011–0570; FRL–9480–5]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Adhesives and Sealants Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving a State Implementation Plan (SIP) revision submitted by the State of Maryland. This SIP revision pertains to amendments to Maryland's rule for the control of volatile organic compound (VOC) emissions from chemical production and polytetrafluoroethylene operations; from paint, resin, and adhesive manufacturing; and from adhesive and sealant application. This SIP revision also pertains to an addition of a new regulation for the control of VOC emissions from adhesives and sealants. EPA is approving this SIP revision to meet the requirements of a reasonably available control technology (RACT) rule for the miscellaneous industrial adhesives control techniques guideline (CTG) category in accordance with the requirements of the Clean Air Act (CAA).

DATES: *Effective Date:* This final rule is effective on November 17, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID Numbers EPA–R03–OAR–2011–0491 and EPA–R03–OAR–2011–0570. All documents in the docket are listed in the *www.regulations.gov* Web site. Although listed in the electronic docket, some information is not publicly available, i.e., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy for public inspection during normal business hours at the Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103. Copies of the State submittal are available at the Maryland Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

FOR FURTHER INFORMATION CONTACT: Rose Quinto, (215) 814–2182 or by e-mail at quinto.rose@epa.gov.

SUPPLEMENTARY INFORMATION:

I. Background

On August 19, 2011 (76 FR 51925), EPA published a notice of proposed rulemaking (NPR) for the State of Maryland. The NPR proposed approval of Maryland's adhesives and sealants rule. The formal SIP revisions (#08–02, #09–01, and #10–06) were submitted by the State of Maryland on April 18, 2008, May 28, 2009, and April 22, 2010.

II. Summary of SIP Revision

The SIP revisions consist of the following: (1) Amendments to COMAR 26.11.19.30 ''Control of VOC from Chemical Production and Polytetrafluoroethylene Operations;'' (2) a new regulation for inclusion into the Maryland SIP—COMAR 26.11.35 ''Control of VOC Emissions from Adhesives and Sealants;'' (3) amendments to Regulation .01 under COMAR 26.11.35 by exempting single-ply roof membrane installation and repair adhesives, single-ply roof membrane sealants, and single ply-roof membrane adhesive primers from standards for VOC content during non-ozone seasons through 2011 and throughout the year of 2012; (4) amendments to Regulation .15A under COMAR 26.11.19 ''VOCs from Specific Processes,'' by adding new definitions; and (5) amendments to Regulation .15C(4) under COMAR 26.11.19 by repealing the general emission standard for adhesives and replacing it with the source-specific VOC RACT emission limitation for the application of adhesives and sealants to specialty electronic systems and subsystems for defense and homeland security. These SIP revisions meet the requirement to adopt a RACT for the miscellaneous industrial adhesives CTG category. Other specific requirements and the rationale for EPA's proposed action are explained in the NPR and will not be restated here. No public comments were received on the NPR.

III. Final Action

EPA is approving the adhesives and sealants rule as a revision to the Maryland SIP. This SIP revision meets the requirement to adopt RACT for the miscellaneous industrial adhesives CTG category.

IV. Statutory and Executive Order Reviews

A. General Requirements

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

B. Submission to Congress and the Comptroller General

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United

States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

C. Petitions for Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 19, 2011. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action pertaining to Maryland's adhesives and sealants rule, may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Nitrogen dioxide, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: October 3, 2011.

W.C. Early,

Acting Regional Administrator, Region III.

40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart V—Maryland

■ 2. In § 52.1070, the table in paragraph (c) is amended by revising entries for COMAR 26.11.19.15 and COMAR 26.11.19.30, and adding an entry for COMAR 26.11.35 to read as follows:

§ 52.1070 Identification of plan.

* * * * *

(c) * * *

EPA-APPROVED REGULATIONS IN THE MARYLAND SIP

Code of Maryland administrative regulations (COMAR) citation	Title/subject	State effective date	EPA approval date	Additional explanation/citation at 40CFR 52.1100
*	*	*	*	*
26.11.19 Control of Volatile Organic Compounds from Specific Processes				
*	*	*	*	*
26.11.19.15	Paint, Resin, and Adhesive Manufacturing and Adhesive and Sealant Applications.	4/19/10	10/18/11 [Insert page number where the document begins].	Amendments to Sections .15A and .15C.
*	*	*	*	*
26.11.19.30	Control of Volatile Organic Compounds from Chemical Production and Flouropolymer Material Installations.	4/21/08	10/18/11[Insert page number where the document begins].	Amendments to Sections .30A, .30B, .30C and .30E.
*	*	*	*	*
26.11.35 Volatile Organic Compounds from Adhesives and Sealants				
26.11.35.01	Applicability and Exemptions	4/21/08 6/1/09	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.02	Incorporation by Reference	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.03	Definitions	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.04	Standards	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.05	Administrative Requirements	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.06	Compliance Procedures and Test Methods.	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
26.11.35.07	Container Labeling	4/21/08	10/18/11 [Insert page number where the document begins].	New Section.
*	*	*	*	*

* * * * *

[FR Doc. 2011–26900 Filed 10–17–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2010–0741–201071; FRL–9476–5]

Approval and Promulgation of Implementation Plans; North Carolina: Prevention of Significant Deterioration; Greenhouse Gas Tailoring Rule Revision

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is taking final action to approve a revision to the State Implementation Plan (SIP), submitted by the State of North Carolina, through the North Carolina Department of Environment and Natural Resources' (NC DENR) Division of Air Quality, to EPA on August 11, 2010, for parallel processing. NC DENR submitted the final version of this SIP revision on May 17, 2011. The SIP revision establishes new NC DENR air quality regulations, specific to the regulation of greenhouse gases (GHGs) under North Carolina's New Source Review (NSR) Prevention of Significant Deterioration (PSD) program. Specifically, the SIP revision establishes appropriate emission thresholds for determining which new stationary sources and modification projects become subject to North Carolina's PSD permitting requirements for their GHG emissions. This rule incorporates state law changes into the federally approved SIP, and specifically, clarifies the applicable thresholds in the North Carolina SIP for GHG PSD requirements. EPA is approving North Carolina's May 17, 2011, SIP revision because the Agency has made the determination that this SIP revision is in accordance with the Clean Air Act (CAA or Act) and EPA regulations, including regulations pertaining to PSD permitting for GHGs. Additionally, EPA is responding to adverse comments received on EPA's November 5, 2010, proposed approval of North Carolina's August 11, 2010, draft SIP revision.

DATES: *Effective Date:* This rule will be effective November 17, 2011.

ADDRESSES: EPA has established a docket for this action under Docket Identification No. EPA–R04–OAR–2010–0741. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *i.e.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section for further information. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: For information regarding the North Carolina SIP, contact Ms. Twunjala Bradley, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. Ms. Bradley's telephone number is (404) 562–9352; e-mail address: *bradley.twunjala@epa.gov*. For information regarding the Tailoring Rule, contact Ms. Heather Abrams, Air Permits Section, at the same address above. Ms. Abrams' telephone number is (404) 562–9185; e-mail address: *abrams.heather@epa.gov*.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. What is the background for this final action?
II. What is EPA's response to comments received on this action?
III. What is the effect of this final action?
IV. Final Action
V. Statutory and Executive Order Reviews

I. What is the background for this final action?

EPA has recently undertaken a series of actions pertaining to the regulation of GHGs that, although for the most part distinct from one another, establish the overall framework for today's final action on the North Carolina SIP. Four of these actions include, as they are commonly called, the ''Endangerment Finding'' and ''Cause or Contribute Finding,'' which EPA issued in a single final action,[1] the ''Johnson Memo Reconsideration,'' [2] the ''Light-Duty Vehicle Rule,'' [3] and the ''Tailoring Rule.'' [4] Taken together and in conjunction with the CAA, these actions established regulatory requirements for GHGs emitted from new motor vehicles and new motor vehicle engines; determined that such regulations, when they took effect on January 2, 2011, subjected GHGs emitted from stationary sources to PSD requirements; and limited the applicability of PSD requirements to GHG sources on a phased-in basis.

On August 11, 2010, in response to the Tailoring Rule and earlier GHG-related EPA rules, NC DENR submitted a draft revision to EPA for approval into the North Carolina SIP to establish appropriate emission thresholds for determining which new or modified stationary sources become subject to North Carolina's PSD permitting requirements for GHG emissions. Subsequently, on November 5, 2010, EPA published a proposed rulemaking to approve a portion of North Carolina's August 11, 2010, SIP revision under parallel processing. *See* 75 FR 68279. Specifically, North Carolina's August 11, 2010, draft SIP revision incorporates by reference the Tailoring Rule provisions at 40 Code of Federal Regulations (CFR) 51.166 (as amended June 3, 2010, and effective August 2, 2010), into the North Carolina SIP at 15A North Carolina Administrative Code (NCAC) 02D .0544—*Prevention of Significant Deterioration Requirements for Greenhouse Gases,* to address the thresholds for GHG permitting applicability. Detailed background information and EPA's rationale for the proposed approval are provided in EPA's November 5, 2010, **Federal Register** notice.

EPA's November 5, 2010, proposed approval was contingent upon North Carolina providing a final SIP revision that was substantively the same as the revision proposed for approval by EPA in the November 5, 2010, proposed rulemaking. *See* 75 FR 68279. North Carolina provided its final SIP revision on May 17, 2011. In its final SIP revision, North Carolina made minor

[1] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act.'' 74 FR 66496 (December 15, 2009).

[2] ''Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs.'' 75 FR 17004 (April 2, 2010).

[3] ''Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule.'' 75 FR 25324 (May 7, 2010).

[4] ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule.'' 75 FR 31514 (June 3, 2010).

formatting changes, and added a couple of clarifications. The formatting changes included changing a couple of periods to semicolons and adding the word ''and'' behind a semicolon to transition to the next statement. With regard to the clarifications, North Carolina deleted the phrase ''Except for 40 CFR 81.334'' and added a notation to explicitly identify the effective date of the Federal Tailoring Rule (*i.e.,* August 2, 2010) that is being incorporated by reference by North Carolina. Besides the minor formatting changes and the aforementioned clarifications, there were no differences between North Carolina's August 11, 2010, draft SIP revision, and the final SIP revision which was provided on May 17, 2011.

On December 30, 2010, EPA published a final rule which narrowed its previous approval of PSD programs as applicable to GHG-emitting sources in SIPs for 24 states, including North Carolina.[5] *See* 75 FR 82536 (PSD Narrowing Rule). Specifically, in the PSD Narrowing Rule, EPA withdrew its previous approval of North Carolina's SIP to the extent it applied PSD to GHG-emitting sources below the thresholds in the final Tailoring Rule.

The effect of the PSD Narrowing Rule on the approved North Carolina SIP was to establish that new and modified sources are subject to PSD permitting requirements for their GHG emissions only if they emit GHGs at or above the Tailoring Rule's emission thresholds. As result of today's action approving North Carolina's incorporation of the appropriate GHG permitting thresholds into its SIP, paragraph (c) in 40 CFR 52.1772, as included in EPA's Narrowing Rule, is no longer necessary, Thus, today's action also amends section 40 CFR 52.572 to remove this unnecessary regulatory language.

II. What is EPA's response to comments received on this action?

EPA received three sets of comments on the November 5, 2010, proposed rulemaking to approve revisions to North Carolina's SIP. One set of comments, provided by the Sierra Club, was in favor of EPA's November 5, 2010, proposed action. The other two sets of comments, provided by the Air Permitting Forum and the John Locke Foundation, raised concerns with final action on EPA's November 5, 2010, proposed action. A full set of the comments provided by the Sierra Club, the Air Permitting Forum (hereinafter referred to as the ''Commenter'') and the John Locke Foundation (also hereinafter referred to as the ''Commenter'') is provided in the docket for today's final action. The comments can be accessed at *http://www.regulations.gov* using Docket ID No. EPA–R04–OAR–2010–0741. A summary of the adverse comments and EPA's responses are provided below.

Generally, the adverse comments fall into six categories. First, the Commenter asserts that PSD requirements cannot be triggered by GHGs. Second, the Commenter expresses concerns regarding a footnote in the November 5, 2010, proposal describing EPA's previously announced intention to narrow its prior approval of some SIPs to ensure that sources with GHG emissions that are less than the Tailoring Rule's thresholds will not be obligated under federal law to obtain PSD permits prior to a SIP revision incorporating those thresholds. The Commenter explains that the planned SIP approval narrowing action, which has now resulted in the PSD Narrowing Rule, ''is illegal.'' Third, the Commenter states that EPA has failed to meet applicable statutory and executive order review requirements. Fourth, the Commenter states: ''EPA should explicitly state in any final rule that the continued enforceability of these provisions in the North Carolina SIP is limited to the extent to which the federal requirements remain enforceable.'' Fifth, the Commenter states that ''EPA does not have statutory authority for the Tailoring Rule.'' Lastly, the Commenter recommends that EPA re-propose the action once North Carolina has finalized its changes to the SIP. EPA's responses to these six categories of comments are provided below.

Comment 1: The Commenter asserts that PSD requirements cannot be triggered by GHGs. In its letter, the Commenter reiterates EPA's statement that without the Tailoring Rule thresholds, PSD will apply as of January 2, 2011, to all stationary sources that emit or have the potential to emit, depending on the source category, either 100 or 250 tons of GHG per year. The Commenter also reiterates EPA's statement that beginning January 2, 2011, a source owner proposing to construct any new major source that emits at or above the GHG applicability levels, or modifies any existing major source in a way that would increase GHG emissions, would need to obtain a PSD permit that addresses these emissions before construction could begin. In raising concerns with the two aforementioned statements, the Commenter states: ''[n]o area in the State of North Carolina has been designated attainment or unclassifiable for greenhouse gases (GHGs), as there is no national ambient air quality standard (NAAQS) for GHGs. Therefore, GHGs cannot trigger PSD permitting.'' The Commenter notes that it made this argument in detail in comments submitted to EPA on the Tailoring Rule and other related GHG rulemakings. The Commenter attached those previously submitted comments to its comments on the proposed rulemaking related to this action. Finally, the Commenter states that ''EPA should immediately provide notice that it is now interpreting the Act not to require that GHGs trigger PSD and allow North Carolina to rescind that portion of its rules that would allow GHGs to trigger PSD.''

Response 1: EPA established the requirement that PSD applies to all pollutants newly subject to regulation, including non-NAAQS pollutants such as GHGs, in earlier national rulemakings concerning the PSD program, and EPA has not re-opened that issue in this rulemaking. In an August 7, 1980, rulemaking at 45 FR 52676, 45 FR 52710–52712, and 45 FR 52735, EPA stated that a ''major stationary source'' was one which emitted ''any air pollutant subject to regulation under the Act'' at or above the specified numerical thresholds; and defined a ''major modification,'' in general, as a physical or operational change that increased emissions of ''any pollutant subject to regulation under the Act'' by more than an amount that EPA variously termed as de minimis or significant. In addition, EPA's 2002 NSR Reform rules EPA added to the PSD regulations the new definition of ''regulated NSR pollutant'' (currently codified at 40 CFR 52.21(b)(50) and 40 CFR 51.166(a)(49)) and; noted that EPA added this term based on a request from a commenter to ''clarify which pollutants are covered under the PSD program.'' Further EPA explained that in addition to criteria pollutants for which a NAAQS has been established, ''[t]he PSD program applies automatically to newly regulated NSR pollutants, which would include final promulgation of an NSPS [new source performance standard] applicable to a previously unregulated pollutant.'' *See* 67 FR 80186, 80240 and 80264 (December 31, 2002). Among other things, the definition of ''regulated NSR pollutant'' includes ''[a]ny pollutant that otherwise is subject to regulation under the Act.'' *See* 40 CFR 52.21(b)(50)(d)(iv); 40 CFR 51.166(a)(49)(iv).

EPA disagrees with the Commenter's underlying premise that PSD

[5] ''Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans.'' 75 FR 82536 (December 30, 2010).

requirements were not triggered for GHGs when GHGs became subject to regulation on January 2, 2011. This has been well established and discussed in connection with prior EPA actions, including, most recently, the Johnson Reconsideration and the Tailoring Rule. In addition, EPA's November 5, 2010, proposed rulemaking action provides the general basis for the Agency's rationale that GHGs, while not a NAAQS pollutant, can trigger PSD permitting requirements. The November 5, 2010, action also refers the reader to the preamble of the Tailoring Rule for further information on this rationale. In that rulemaking, EPA addressed at length the comment that PSD can be triggered only by pollutants subject to the NAAQS, and concluded such an interpretation of the Act would contravene Congress' unambiguous intent. *See* 75 FR 31560–31562. Further discussion of EPA's rationale for concluding that PSD requirements are triggered by non-NAAQS pollutants such as GHGs appears in the Tailoring Rule Response-to-Comments document (''Prevention of Significant Deterioration and Title V GHG Tailoring Rule: EPA's Response to Public Comments''), pp. 34–41; and in EPA's response to motions for a stay filed in the litigation concerning those rules (''EPA's Response to Motions for Stay,'' *Coalition for Responsible Regulation* v. *EPA,* D.C. Cir. No. 09–1322 (and consolidated cases)), at pp. 47–59, and are incorporated by reference here. These documents have been placed in the docket for today's action and can be accessed at *http://www.regulations.gov* using Docket ID No. EPA–R04–OAR–2010–0741.

Comment 2: The Commenter expresses concerns regarding a footnote in which EPA describes its previously announced intention to narrow its prior approval of some SIPs. In the footnote, EPA explained that such narrowing would ensure that sources with GHG emissions that are less than the Tailoring Rule's thresholds are not obligated under federal law to obtain PSD permits during any gap between the effective date of GHG-permitting requirements (January 2, 2011) and the date that a SIP is revised to incorporate the Tailoring Rule thresholds. The Commenter asserts that EPA's narrowing of its prior SIP approvals ''is illegal.'' Further, the Commenter states that ''EPA has *not* proposed to narrow North Carolina's SIP approval here and any such proposal must be explicit and address the action specifically made with respect to North Carolina's. EPA cannot sidestep these important procedural requirements.''

Response 2: While EPA disagrees with the Commenter's assertion that the narrowing approach discussed in EPA's Tailoring Rule is illegal, the narrowing approach was not the subject of EPA's November 5, 2010, proposed rulemaking to approve North Carolina's August 11, 2010, SIP revision. Rather, the narrowing approach was the subject of a separate rulemaking, which was considered and finalized in the PSD Narrowing Rule in an action separate from today's rulemaking. *See* 75 FR 82536 (December 30, 2010). In today's final action, EPA is acting to approve a SIP revision submitted by North Carolina, and is not otherwise narrowing its approval of prior submitted and approved provisions in the North Carolina SIP. Accordingly, the legality of the narrowing approach is not at issue in this rulemaking.

Comment 3: The Commenter states that EPA has failed to meet applicable statutory and executive order review requirements. Specifically, the Commenter refers to the statutory and executive orders for the Paperwork Reduction Act, the Regulatory Flexibility Act (RFA), Unfunded Mandates Reform Act, and Executive Order 13132 (Federalism). Additionally, the Commenter mentions that EPA has never analyzed the costs and benefits associated with triggering PSD for stationary sources in North Carolina, much less nationwide.

Response 3: EPA disagrees with the Commenter's statement that EPA has failed to meet applicable statutory and executive order review requirements. As stated in EPA's proposed approval of North Carolina's May 17, 2011, SIP revision, this action merely approves state law as meeting federal requirements and does not impose additional requirements beyond those imposed by state law. Accordingly, EPA approval, in and of itself, does not impose any new information collection burden, as defined in 5 CFR 1320.3(b) and (c), that would require additional review under the Paperwork Reduction Act. In addition, because today's action simply approves existing state law, it will not have a significant economic impact on a substantial number of small entities beyond the impact of existing state law requirements. Thus, a regulatory flexibility analysis is not required under the RFA. Accordingly, this rule is appropriately certified under section 605(b) of the RFA. Moreover, as this action approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandates or significantly or uniquely affect small governments, such that it would be subject to the Unfunded Mandates Reform Act. Finally, this action does not have federalism implications that would make Executive Order 13132 applicable because it merely approves a state rule implementing a federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the CAA.

In sum, today's rule is a routine approval of a SIP revision, approving state law, and does not impose any requirements beyond those imposed by state law. To the extent these comments are directed more generally to the application of the statutory and executive order reviews to the required regulation of GHGs under PSD programs, EPA provided an extensive response to similar comments in promulgating the Tailoring Rule. EPA refers the Commenter to the sections in the Tailoring Rule entitled *''VII. Comments on Statutory and Executive Order Reviews,''* 75 FR 31601–31603, and *''VI. What are the economic impacts of the final rule?,''* 75 FR 31595–31601. EPA also notes that today's action is not itself the trigger for regulation of GHGs. To the contrary, by helping to clarify that higher PSD applicability thresholds for GHGs apply than would otherwise be in effect under the Act, this rulemaking, as well as EPA's Tailoring Rule, is part of the effort to provide relief to smaller GHG-emitting sources that would otherwise be subject to PSD permitting requirements for their GHG emissions.

Comment 4: The Commenter states that ''[i]f EPA proceeds with this action, it must condition approval on the continued validity of its determination that PSD can be triggered by or is applicable to GHGs.'' Further, the Commenter remarks on the ongoing litigation in the U.S. Court of Appeals for the D.C. Circuit. Specifically, regarding EPA's determination that PSD can be triggered by GHGs or is applicable to GHGs, the Commenter mentions that ''EPA should explicitly state in any final rule that continued enforceability of these provisions in the North Carolina SIP is limited to the extent to which the federal requirements remain enforceable.'' The Commenter notes that if a stay is issued, these requirements should also be stayed.

Response 4: EPA believes that it is most appropriate to take actions that are consistent with the federal regulations that are in place at the time the action is being taken. To the extent that any changes to federal regulations related to

today's action result from pending legal challenges or other actions, EPA will process appropriate SIP revisions in accordance with the procedures provided in the Act and EPA's regulations. EPA notes that in an order dated December 10, 2010, the United States Court of Appeals for the D.C. Circuit denied motions to stay EPA's regulatory actions related to GHGs. *Coalition for Responsible Regulation, Inc.* v. *EPA,* Nos. 09–1322, 10–1073, 10–1092 (and consolidated cases), Slip Op. at 3 (D.C. Cir. December 10, 2010) (order denying stay motions).

Comment 5: The Commenter states that ''EPA does not have statutory authority for the Tailoring Rule.'' Additionally, the Commenter states that ''EPA's proposal to revise North Carolina's SIP to include greenhouse gases (GHG) is grounded in an improper interpretation of the Clean Air Act (CAA). Specifically, the EPA is ignoring the plain and unambiguous language of the CAA to justify the regulation of GHG. If the EPA did not change the threshold levels for GHG, by the agency's own admission, there would be 'absurd' results.''

Response 5: While EPA does not agree with the Commenter's statement that ''EPA does not have statutory authority for the Tailoring Rule,'' EPA notes that the statutory authority for the Tailoring Rule was not the subject of EPA's November 5, 2010, proposed rulemaking to approve North Carolina's August 11, 2010, SIP revision. Rather, the requirements of the Tailoring Rule were the subject of a separate rulemaking. In EPA's final action for the Tailoring Rule, EPA provided extensive discussion and response to comments regarding legality of the Tailoring Rule in a section entitled, *''V. What is the Legal and Policy Rationale for the Final Action?'' See* 75 FR 31527–31595. In today's final action, EPA is taking action to approve a SIP revision submitted by North Carolina, and is not reopening comment on the legality of the Tailoring Rule.

Comment 6: The Commenter mentions that the ''comments being provided to EPA are based on proposed revisions, not final revisions,'' and that ''the differences between the proposed and final North Carolina revisions may or may not be substantial, but they certainly could affect how the public comments on the EPA's proposed rule.'' The Commenter states ''it is unclear why the EPA believes it is appropriate and legally supportable to seek comments on a yet-to-be finalized revision to a SIP. Further, it is not clear what would constitute 'significant changes' that would require the EPA to re-propose the action.'' The Commenter concludes by recommending that EPA re-propose the action once North Carolina has finalized its changes to the SIP.

Response 6: The procedure utilized by EPA to solicit public comment on North Carolina's SIP revision was appropriate and lawful. As explained in EPA's proposal at 75 FR 68279, EPA utilized a ''parallel processing'' procedure for this SIP revision. Under this procedure, EPA proposes rulemaking action concurrently with the State's procedures for approving a SIP submittal and amending its regulations (40 CFR part 51, appendix V, 2.3). EPA reviews that SIP submittal, even though the regulation is not yet adopted in final form by the State, as if it were a final, adopted regulation. In doing so, EPA evaluates the draft regulation against the same approvability criteria as any other SIP submittal. Thus, EPA has not used the ''parallel processing'' procedure to avoid any statutory requirements. In this case, as explained earlier in this action, EPA has determined that the minor differences between the draft and final regulations are insignificant and do not warrant re-proposal of this action. Accordingly, the proposal gave the public the appropriate opportunity to comment on the substance of the SIP revision for which EPA is today issuing a final approval.

III. What is the effect of this final action?

Final approval of North Carolina's May 17, 2011, SIP revision will put in place the GHG emission thresholds for PSD applicability set forth in EPA's Tailoring Rule (75 FR 31514, June 3, 2010) and adopted as state law, making clear that smaller GHG sources emitting less than these thresholds will not be subject to permitting requirements under the approved North Carolina SIP. Pursuant to section 110 of the CAA, EPA is approving the changes made in North Carolina's May 17, 2011, SIP revision into North Carolina's SIP.

North Carolina's May 17, 2011, revision establishes a new regulation specifically to incorporate by reference the relevant federal Tailoring Rule provisions set forth at 40 CFR 51.166 into the North Carolina SIP at 15A North Carolina Administrative Code (NCAC) 02D .0544—*Prevention of Significant Deterioration Requirements for Greenhouse Gases.* EPA has determined that North Carolina's May 17, 2011, SIP revision is consistent with the Tailoring Rule. Furthermore, EPA has determined that the May 17, 2011, revision to North Carolina's SIP is consistent with section 110 of the CAA. *See, e.g.,* Tailoring Rule, 75 FR 31561.

IV. Final Action

EPA is taking final action to approve North Carolina's May 17, 2011, SIP revision which includes updates to North Carolina's air quality regulations, 15A North Carolina Administrative Code (NCAC) 02D .0544—*Prevention of Significant Deterioration Requirements for Greenhouse Gases.* Specifically, North Carolina's May 17, 2011, SIP revision clarifies appropriate emissions thresholds for determining PSD applicability with respect to new or modified GHG-emitting sources in accordance with EPA's Tailoring Rule, and incorporates those thresholds in the form in which they are stated in state law. EPA has made the determination that the May 17, 2011, SIP revision is approvable because it is in accordance with the CAA and EPA regulations, including regulations pertaining to PSD permitting for GHGs.

As result of EPA's approval of North Carolina's changes to its air quality regulations to incorporate the appropriate thresholds for GHG permitting applicability into North Carolina's SIP, paragraph (c) in Section 52.1772 of 40 CFR part 52, as included in EPA's Narrowing Rule, is no longer necessary. In today's final action EPA is also amending Section 52.1772 of 40 CFR part 52 to remove this unnecessary regulatory language.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely

affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);

• Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

• Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

• Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

• Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and

• Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 19, 2011. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. *See* CAA section 307(b)(2), 42 U.S.C. 7607(b)(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Greenhouse gases, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: September 20, 2011.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart II—North Carolina

■ 2. Section 52.1770(c) Table 1, is amended under Subchapter 2D, Section .0500 by adding a new entry ''Sect .0544'' to read as follows:

§ 52.1770 Identification of plan.

* * * * *

(c) * * *

TABLE 1—EPA APPROVED NORTH CAROLINA REGULATIONS

State citation	Title/subject	State effective date	EPA approval date	Explanation
Subchapter 2D Air Pollution Control Requirements				
* *	*	*	* *	*
Section .0500 Emission Control Standards				
* *	*	*	* *	*
Sect .0544	Prevention of Significant Deterioration Requirements for Greenhouse Gases.	12/16/10	October 18, 2011, [Insert citation of publication].	
* *	*	*	* *	*

* * * * *

§ 52.1772 [Amended]

■ 3. Section 52.1772 is amended by removing paragraph (c).

[FR Doc. 2011–26898 Filed 10–17–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 112

[EPA–HQ–OPA–2011–0838; FRL–9481–4]

RIN 2050–AG59

Oil Pollution Prevention; Spill Prevention, Control, and Countermeasure (SPCC) Rule—Compliance Date Amendment for Farms

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is taking direct final action to amend the date by which farms must prepare or amend, and implement their Spill Prevention, Control, and Countermeasure Plans to May 10, 2013.

DATES: This rule is effective on November 7, 2011 without further notice, unless EPA receives adverse comment by November 2, 2011. If EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect. For more information on effective and comment dates, see **SUPPLEMENTARY INFORMATION**.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OPA–2011–0838, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: Docket.RCRA@epa.gov.*
- *Fax:* 202–566–9744.
- *Mail:* EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Attention Docket ID No. EPA–HQ–OPA–2011–0838. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OPA–2011–0838. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA–HQ–OPA–2011–0838. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (202) 566–1744. EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: For general information, contact the Superfund, TRI, EPCRA, RMP and Oil Information Center at (800) 424–9346 or TDD (800) 553–7672 (hearing impaired). In the Washington, DC metropolitan area, call (703) 412–9810 or TDD (703) 412–3323. For more detailed information on specific aspects of this final rule, contact either Lynn Beasley at (202) 564–1965 (*beasley.lynn@epa.gov*) or Mark W. Howard at (202) 564–1964 (*howard.markw@epa.gov*), U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0002, Mail Code 5104A.

SUPPLEMENTARY INFORMATION: EPA is providing 15 days for adverse comment. EPA is providing a review time of 15 days because the amendment to the compliance date is straightforward and there are no additional amendments to the regulation. In addition, there is a certain urgency of to this rule due to the impact that flooding has had on farms to comply with this regulation, the low likelihood of comment, and the fact that the targeted community is aware that an extension is under consideration. Interested parties should be able to express their comments within the 15 day period through electronic means. There is no requirement to delay the effective date, because this rule relieves a restriction and grants an exemption by extending the compliance date of the Spill, Prevention, Control, and Countermeasure rule. 5 U.S.C. 553(d)(1). It is also not a ''major rule'' for the purposes of the Congressional Review Act. If EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect.

I. Why is EPA using a direct final rule?

EPA is publishing this rule without a prior proposed rule because we view this as a noncontroversial action and anticipate no adverse comment since this action provides owners and operators of farms an additional 18 months to prepare or amend, and implement their Spill Prevention, Control, and Countermeasure (SPCC) Plan. This action does not add an additional burden to comply with the regulations contained in 40 CFR part 112—Oil Pollution Prevention. However, in the ''Proposed Rules'' section of today's **Federal Register**, we are also publishing a separate proposed rule to provide owners and operators of farms an additional 18 months to prepare or amend, and implement their SPCC Plan, if adverse comments are received on this direct final rule. We will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document.

If EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that this direct final rule will not take effect. We would address all public comments in any subsequent final rule based on the proposed rule.

II. Does this action apply to me?

Industry sector	NAICS code
Farms	111, 112
Government	92

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

III. What should I consider as I prepare my comments for EPA?

A. *Submitting CBI.* Do not submit this information to EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with the procedures set forth in 40 CFR part 2.

B. *Tips for Preparing Your Comments.* When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible.
- Make sure to submit your comments by the comment period deadline identified.

IV. What does this amendment do?

This direct final rule amends the date by which farms as defined in section 112.2 must prepare or amend, and implement their SPCC Plan to May 10, 2013. A farm is defined in this section as a facility on a tract of land devoted to the production of crops or raising of animals, including fish, which produced and sold, or normally would have produced and sold, $1,000 or more of agricultural products during a year.

On June 19, 2009 (74 FR 29136), EPA issued a final rule in the **Federal Register** that amended the dates by which facilities must prepare or amend their SPCC Plans, and implement those Plans to November 10, 2010. Then on October 14, 2010 (75 FR 63093), EPA issued a final rule in the **Federal Register** with a new compliance date of November 10, 2011, by which certain facilities must prepare or amend and implement their SPCC Plans, providing an additional year for the remaining facilities. This action further extends the compliance date to May 10, 2013 for the owners or operators of farms as defined in 40 CFR 112.2. The Agency recognizes that the owners or operators of some facilities excluded from the extension of the compliance date may still require additional time to amend or prepare their SPCC Plans as a result of either non-availability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of the owner or operator. If so, the owner or operator of the facility may submit a written request for additional time to amend or prepare a SPCC Plan to the Regional Administrator in accordance with § 112.3(f). This rule is not the vehicle for other extensions. EPA is not extending the compliance date for any other facilities as other facilities are not season-dependent and are less likely to be impacted by severe weather conditions. Additionally, other facilities retain the alternative mechanism for requesting an extension to the compliance date through § 112.3(f). Interested facilities may also petition the agency to consider additional rulemaking.

A large segment of the continental United States was affected by flooding during the spring and summer of 2011. Other areas were impacted by devastating fires and drought conditions. Many counties in several States were declared disaster areas by either the Federal or their State government or both. EPA has received a number of letters and other correspondence, from State Agricultural Departments and other parties, explaining the impact of these recent floods on the owners and operators of farms and their ability to comply with the SPCC rule. These owners and operators have experienced interruptions in planting, cultivation and harvesting due to these floods. According to the Federal Emergency Management Agency (FEMA) in 2011, the Agency issued 56 Major Disaster/Emergency Declarations specifically associated with flooding events. According to FEMA's 2011 data, approximately two thirds of the fifty states had a FEMA flooding Major Disaster/Emergency Declarations. Almost a quarter of the fifty states had multiple FEMA declarations due to flooding.[1] These declarations are widespread throughout the crop production areas of the country. The Agency was also advised in the correspondence that there may be a lack of available qualified Professional Engineers (PEs) in some areas of the country to assist in the preparation, implementation, and review of SPCC Plans for farms.

In addition, despite the targeted farm outreach efforts by EPA over the past ten months, the sheer number of farms throughout the U.S. makes it a challenge to reach those owners and operators of farms that may be subject to the SPCC Plan regulations. As a result, the Agency believes that farms, as defined in section 112.2, need additional time to come into compliance with the requirements to prepare or amend and implement a SPCC Plan. Thus, the Agency has decided to extend the compliance date by which owners or operators of a farm must prepare or amend and implement a SPCC Plans to May 10, 2013. The additional 18 months allows enough time for farms to come in compliance with this regulation. The owners and operators of farms are strongly encouraged not to delay, and to take advantage of the off-season for planting and growing, in preparing their SPCC Plans. However, any farm owner or operator who is not able to come into compliance by May 10, 2013, and wishes to seek a further extension of the compliance date, should submit a written request to the Regional Administrator of the EPA Regional Office for the State where the farm is located in accordance with paragraph (f) of 40 CFR 112.3.

The amendment to the compliance date does not remove the regulatory requirement for owners or operators of farms in operation before August 16,

[1] *http://www.fema.gov/news/disasters.fema.*

2002, to have and to maintain and continue implementing a SPCC Plan in accordance with the SPCC regulations then in effect. Such owners and operators continue to be required to maintain plans during the interim until the applicable compliance date for amending and implementing the amended Plans. In addition, the amendment of the compliance date does not relieve the owners and operators of farms from the potential liability under the Clean Water Act or other environmental statutes or regulations for any spills (see 40 CFR part 110) that may occur.

IV. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

This direct final action does not impose any new information collection burden. The amendments in this direct final rule simply extend the compliance date for farms. This direct final rule does not change any reporting requirements in the general provisions. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing subparts of 40 CFR 112 under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2050–0021. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. Subparts that will be added through separate rulemakings will document the respective information collection requirements in their own ICR documents.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The direct final rule simply amends the date for compliance. The direct final rule does not itself add any additional subparts or requirements. The direct final rule will not impose any new requirements on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains no Federal mandates under the provisions of title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 or 205 of the UMRA. This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The amendments in this final rule change the dates for compliance for farms.

E. Executive Order 13132: Federalism

Executive Order (EO) 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications.'' ''Policies that have Federalism implications'' is defined in the EO to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have Federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132.

This amendment applies directly to farms. They do not apply to governmental entities unless the government entity owns a farm, as defined in 40 CFR 112.2 Definitions. This regulation also does not limit the power of States or localities to regulate farms. Thus, EO 13132 does not apply to this final rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The changes in this direct final rule do not result in any changes to the requirements of the 2009 rule. Thus Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This direct final rule is not subject to EO 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in EO 12866, and because the Agency does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. The changes in this direct final rule do not result in any changes to the requirements applicable to farms, final rule other than the date for compliance.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations

when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that the direct final amendments will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because the amendments do not affect the level of protection provided to human health or the environment.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective November 7, 2011.

List of Subjects in 40 CFR Part 112

Oil pollution prevention, Farms, Compliance date, Reporting and recordkeeping requirements.

Dated: October 13, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set out above, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 112—OIL POLLUTION PREVENTION

■ 1. The authority citation for part 112 continues to read as follows:

Authority: 33 U.S.C. 1251 *et seq.;* 33 U.S.C. 2720; and E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

■ 2. Section 112.3 is amended by adding paragraph (a)(3) to read as follows:

§ 112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.

* * * * *

(a) * * *

(3) If your farm, as defined in § 112.2, was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, and implement the amended Plan no later than May 10, 2013. If your farm becomes operational after August 16, 2002, through May 10, 2013, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan on or before May 10, 2013. If your farm becomes operational after May 10, 2013, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations.

* * * * *

[FR Doc. 2011–27047 Filed 10–17–11; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 622

[Docket No. 040205043–4043–01]

RIN 0648–XA766

Gulf of Mexico Reef Fish Fishery; Closure of the 2011 Gulf of Mexico Commercial Sector for Greater Amberjack

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; closure.

SUMMARY: NMFS closes the commercial sector for greater amberjack in the exclusive economic zone (EEZ) of the Gulf of Mexico (Gulf). These actions are necessary to reduce overfishing of the Gulf greater amberjack resource.

DATES: The closure of the commercial sector for Gulf greater amberjack is effective 12:01 a.m., local time, October 20, 2011, until 12:01 a.m., local time, on January 1, 2012.

ADDRESSES: Electronic copies of the final rule for Amendment 30A, the Final Supplemental Environmental Impact Statement (FSEIS) for Amendment 30A, and other supporting documentation may be obtained from Steve Branstetter, NMFS, Southeast Regional Office, 263 13th Avenue, South, St. Petersburg, FL 33701; telephone: 727–824–5305.

FOR FURTHER INFORMATION CONTACT: Steve Branstetter, telephone: 727–824–5305, e-mail: *Steve.Branstetter@noaa.gov.*

SUPPLEMENTARY INFORMATION: The reef fish fishery of the Gulf is managed under the Fishery Management Plan for Reef Fish Resources of the Gulf of Mexico (FMP). The FMP was prepared by the Gulf of Mexico Fishery Management Council (Council) and is implemented under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) by regulations at 50 CFR part 622.

Background

The 2006 reauthorization of the Magnuson-Stevens Act implemented new requirements that annual catch limits (ACLs) and accountability measures (AMs) be established to end overfishing and prevent overfishing from occurring. AMs are management controls to prevent ACLs from being exceeded, and to correct or mitigate overages of the ACL if they occur. Section 303(a)(15) of the Magnuson-Stevens Act mandates the establishment of ACLs at a level such that overfishing does not occur in the fishery, including measures to ensure accountability.

On July 3, 2008, NMFS issued a final rule (73 FR 38139) to implement Amendment 30A to the FMP (Amendment 30A). Amendment 30A established a commercial quota for Gulf greater amberjack of 503,000 lb (228,157 kg) and an AM that would go into effect if the commercial quota for greater amberjack is exceeded. In accordance with regulations at 50 CFR 622.49(a)(1)(i), when the applicable commercial quota is reached, or projected to be reached, the Assistant Administrator for Fisheries, NOAA, (AA), will file a notification with the Office of the Federal Register to close the commercial sector for the remainder of the fishing year. If despite such closure, commercial landings exceed the quota, the AA will reduce the quota the year following an overage by the amount of the overage of the prior fishing year.

Landings data for 2010, provided by the Southeast Fisheries Science Center (SEFSC) in April, 2011, indicated that 562,172 lb (254,997 kg) were landed by the commercial sector for the 2010 fishing year, for a commercial sector overage of 189,100 lb (85,774 kg). Therefore, for 2011, NMFS published a rule in the **Federal Register** (76 FR 23909, April 29, 2011) announcing the 503,000-lb commercial quota would be adjusted to 313,900 lb (142,383 kg) to account for the 2010 overage of the commercial sector.

The greater amberjack commercial sector was closed on June 18, 2011, when NMFS estimated the 313,900-lb (142,383-kg) adjusted quota would be reached (76 FR 23909, April 29, 2011). However, subsequent updated landings data, provided by the SEFSC in 2011, indicated that the actual commercial harvest for 2010 was 533,981 lb (242,210 kg), 28,191 lb (12,787 kg) less than was previously reported. Therefore, for the 2011 fishing year, NMFS published a rule in the **Federal Register** (76 FR 51905, August 19, 2011) announcing the 503,000-lb commercial quota was again adjusted to establish a new 2011 adjusted commercial quota of 342,091 lb (155,170 kg).

Additional landings data that became available in August of 2011 indicated that the adjusted commercial quota had not been met when the commercial sector was previously closed on June 18, 2011,and that 86,452 lb (39,214 kg) of commercial quota remained available for the 2011 fishing year. Based on historical catch rates, NMFS projected that the remaining 86,452 lb (39,214 kg) of the greater amberjack commercial quota would be harvested in 61 days. Therefore, NMFS reopened the commercial greater amberjack fishing season beginning at 12:01 a.m., local time, September 1, 2011, until 12:01 a.m., local time, on October 31, 2011 to allow for the commercial harvest of the remaining commercial adjusted quota (August 19, 2011, 76 FR 51905).

Based on current statistics, NMFS has determined that the remaining 2011 adjusted commercial quota has been met. Accordingly, NMFS is closing the commercial harvest of greater amberjack in the Gulf EEZ at 12:01 a.m., local time, on October 20, 2011, and it will remain closed until 12:01 a.m., local time, on January 1, 2012. The operator of a vessel with a valid commercial vessel permit for Gulf reef fish having greater amberjack aboard must have landed and bartered, traded, or sold such greater amberjack prior to 12:01 a.m., local time, October 20, 2011.

During the closure, all commercial harvest or possession of greater amberjack in or from the Gulf EEZ, and the sale or purchase of greater amberjack taken from the EEZ is prohibited. The prohibition on sale or purchase does not apply to sale or purchase of greater amberjack that were harvested, landed ashore, and sold prior to 12:01 a.m., local time, October 20, 2011, and were held in cold storage by a dealer or processor. In addition to the Gulf EEZ closure, a person on board a vessel for which a commercial vessel permit for Gulf reef fish has been issued must comply with these closure provisions regardless of where the Gulf greater amberjack are harvested, *i.e.,* in state or Federal waters. This closure is intended to prevent overfishing of Gulf greater amberjack and increase the likelihood that the 2011 quota will not be exceeded.

The 2012 commercial quota for greater amberjack will return to the quota specified at 50 CFR 622.42(a)(1)(v) unless accountability measures are implemented due to a quota overage and a reduced quota is specified through notification in the **Federal Register**, or subsequent regulatory action is taken to adjust the quota.

Classification

The Administrator, Southeast Region, NMFS, (RA) has determined this temporary rule is necessary for the conservation and management of the Gulf greater amberjack component of the Gulf reef fish fishery and is consistent with the Magnuson-Stevens Act and other applicable laws.

The temporary rule has been determined to be not significant for purposes of Executive Order 12866.

These measures are exempt from the procedures of the Regulatory Flexibility Act because the temporary rule is issued without opportunity for prior notice and comment.

NMFS prepared a FSEIS for Amendment 30A. A notice of availability for the FSEIS was published on April 18, 2008 (73 FR 21124). A copy of the FSEIS and the Record of Decision are available from NMFS (see **ADDRESSES**).

This action responds to the best available information recently obtained from the fishery. The AA, finds good cause to waive the requirement to provide prior notice and opportunity for public comment pursuant to the authority set forth at 5 U.S.C. 553(b)(3)(B). Such procedures would be unnecessary because the rule implementing the quota and the associated requirement for closure of commercial harvest when the quota is reached or projected to be reached already has been subject to notice and comment, and all that remains is to notify the public of the closure.

Providing prior notice and opportunity for public comment on this action would be contrary to the public interest because any delay in the closure of commercial harvest could result in the commercial quota for greater amberjack being exceeded, which in turn, would trigger the accountability measure for greater amberjack. The accountability measure would require NMFS to reduce the quota for the following year by the amount of the quota overage from the prior fishing year. Reducing the quota the following year would produce additional adverse economic impacts for Gulf reef fish fishermen. There is a need to implement this measure in a timely fashion to prevent a quota overrun of the greater amberjack commercial sector, given the capacity of the fishing fleet to harvest the quota quickly.

For the aforementioned reasons, the AA also finds good cause to waive the 30-day delay in the effectiveness of this action under 5 U.S.C. 553(d)(3).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 13, 2011.

Steven Thur,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2011–26923 Filed 10–13–11; 4:15 pm]

BILLING CODE 3510–22–P

Proposed Rules

Federal Register
Vol. 76, No. 201
Tuesday, October 18, 2011

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

FEDERAL RESERVE SYSTEM

12 CFR Part 204

[Regulation D; Docket No. R–1433]

RIN No. 7100 AD 83

Reserve Requirements of Depository Institutions: Reserves Simplification and Private Sector Adjustment Factor

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Notice of proposed rulemaking; request for public comment.

SUMMARY: The Board is requesting public comment on proposed amendments to Regulation D, Reserve Requirements of Depository Institutions, to simplify the administration of reserve requirements. The proposed amendments would create a common two-week maintenance period for all depository institutions, create a penalty-free band around reserve balance requirements in place of carryover and routine penalty waivers, discontinue as-of adjustments related to deposit revisions, replace all other as-of adjustments with direct compensation, and eliminate the contractual clearing balance program. The proposed amendments are designed to reduce the administrative and operational costs associated with reserve requirements for both depository institutions and the Federal Reserve. The Board is requesting comment on all aspects of the proposal. In connection with the proposed elimination of the contractual clearing balance program, the Board is requesting comment on several issues related to the methodology used for the Private Sector Adjustment Factor that is part of the pricing of Federal Reserve Bank services.

DATES: Comments must be submitted by December 19, 2011.

ADDRESSES: You may submit comments, identified by Docket No. R–1433 and RIN No. 7100 AD 83, by any of the following methods:

- *Agency Web Site: http://www.federalreserve.gov*. Follow the instructions for submitting comments at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm*.
- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *E-mail: regs.comments@federalreserve.gov*. Include the docket number in the subject line of the message.
- *Fax:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Jennifer J. Johnson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information.

Public comments may also be viewed electronically or in paper in Room MP–500 of the Board's Martin Building (20th and C Streets, NW.) between 9 a.m. and 5 p.m. on weekdays.

FOR FURTHER INFORMATION CONTACT: Kara Handzlik, Senior Attorney (202) 452–3852, Legal Division, or Margaret Gillis DeBoer, Assistant Director (202) 452–3139, or Heather Wiggins, Senior Financial Analyst (202) 452–3674, Division of Monetary Affairs, or, for questions regarding the Private Sector Adjustment Factor, Gregory Evans, Deputy Associate Director (202) 452–3945, or Brenda Richards, Manager (202) 452–2753, Division of Reserve Bank Operations and Payment Systems; for users of Telecommunications Device for the Deaf (TDD) only, contact (202) 263–4869; Board of Governors of the Federal Reserve System, 20th and C Streets, NW., Washington, DC 20551.

SUPPLEMENTARY INFORMATION:

I. Background

Section 19 of the Federal Reserve Act (Act) [1] authorizes the Board of Governors of the Federal Reserve System (Board) to impose reserve requirements on certain deposits and other liabilities of depository institutions for the purpose of implementing monetary policy. The Board's Regulation D (Reserve Requirements of Depository Institutions, 12 CFR part 204) implements section 19 of the Act. Transaction account balances maintained at each depository institution are subject to reserve requirement ratios of zero, three, or ten percent, depending on the level of transaction accounts at that institution.[2] The reserve requirement ratios are set by the Board within the limits mandated by the Act. A depository institution satisfies its reserve requirement by its holdings of vault cash and, if vault cash is insufficient to meet the requirement, by a balance maintained in an account at a Federal Reserve Bank (Reserve Bank). The amount of balances that an institution must maintain if its reserve requirement is not satisfied by vault cash is referred to as the reserve balance requirement. The balance that an institution maintains to satisfy its reserve balance requirement can be maintained either in the institution's own account at a Reserve Bank or in a pass-through correspondent's Reserve Bank account. In 2008, Congress amended the Federal Reserve Act to authorize the Reserve Banks to pay interest on balances of eligible institutions.[3] Since then, interest has been paid on balances maintained to satisfy reserve balance requirements at a rate determined by the Board (currently 25 basis points).[4]

An institution may also maintain a clearing balance to satisfy its contractual clearing balance requirement pursuant to an agreement between the institution and its Reserve Bank. Clearing balances currently generate earning credits, a form of compensation that can be used only to offset service charges an institution incurs through its use of Federal Reserve priced services (earnings credits currently are computed as 80 percent of the rolling 13-week average of the three-month Treasury bill rate). An institution may also maintain excess balances, which are balances held in excess of the balance maintained to satisfy the reserve balance requirement and the contractual clearing balance requirement, in its account at a Reserve Bank. Like balances maintained to satisfy the

[1] 12 U.S.C. 461.

[2] 12 CFR 204.4(f) (reserve requirement ratios).

[3] Emergency Economic Stabilization Act of 2008, Pub. L. 110–343, § 128, 122 Stat. 3765 (2008).

[4] 12 CFR 204.10(b) (rates of interest paid on balances maintained by eligible institutions at Reserve Banks).

reserve balance requirement, since 2008, interest has been paid on excess balances at a rate determined by the Board (currently 25 basis points).

II. Overview of Proposed Simplifications

The Board is proposing four amendments to Regulation D that would simplify the administration of reserve requirements while maintaining the role of reserve requirements in the implementation of monetary policy. The Board believes that these four simplifications will reduce the administrative and operational costs associated with reserve requirements for depository institutions, Reserve Banks, and the Board:

1. Create a common two-week maintenance period for all depository institutions;

2. Create a penalty-free band around reserve balance requirements in place of using carryover and routine penalty waivers (routine penalty waivers are used to eliminate charges for small or infrequent reserve deficiencies);

3. Discontinue as-of adjustments related to deposit revisions and replace all other as-of adjustments with direct compensation; and

4. Eliminate the contractual clearing balance program.

The Board also proposes to make certain changes to various terms used throughout Regulation D in order to clarify the meaning, enhance the accuracy, and ensure the consistent application of those terms. The proposed changes include replacing the term ''required reserve balance'' with ''balances maintained to satisfy the reserve balance requirement,'' adding a new definition of ''reserve balance requirement,'' and making conforming revisions throughout the regulation.

Upon the Board's adoption of final amendments to Regulation D and the Private Sector Adjustment Factor calculation, related Federal Reserve operating circulars and manuals will be updated accordingly.

1. Create a Common Two-Week Maintenance Period for All Depository Institutions

As noted above, a depository institution may satisfy its reserve balance requirement by maintaining a balance in its own account at a Reserve Bank or in a pass-through correspondent's Reserve Bank account. A depository institution satisfies its reserve balance requirement on average over a period of time, known as a maintenance period. Maintenance periods provide depository institutions flexibility, allowing them to meet their reserve balance requirements on average over a period of time rather than on a daily basis.

Regulation D currently provides for two types of maintenance periods, a one-week maintenance period and a two-week maintenance period.[5] To determine which reserve maintenance period applies to an institution, the Board requires depository institutions to submit deposit reports at different frequencies depending on the amount of their reservable liabilities over the preceding year.[6] The Board assigns depository institutions annually to one of four deposit reporting categories (weekly reporters, quarterly reporters, annual reporters, or nonreporters). Depository institutions that have reservable liabilities above the exemption amount[7] and therefore have non-zero reserve requirements are required to submit deposit data at a weekly or quarterly frequency. Of these institutions, those with the sum of transaction accounts, savings deposits, and small time deposits above a certain threshold are required to report weekly and those with the sum of transaction accounts, savings deposits, and small time deposits below the threshold are required to report quarterly. Weekly reporters are subject to a two-week maintenance period and quarterly reporters are subject to a one-week maintenance period. Institutions that have reservable liabilities below the exemption amount (and therefore have a zero reserve requirement) either report annually or are not required to report at all. Annual reporters and nonreporters with a contractual clearing balance are subject to a one-week maintenance period and, as explained above, receive earnings credits on their clearing balances rather than interest payments. Institutions that have neither reserve requirements nor clearing balance requirements receive interest payments on their average balances over a one-week period at the excess balance rate.

From one year to another, some depository institutions switch reporting frequency because of changes in the levels of the institution's reservable liabilities. Specifically, some depository institutions may switch from a two-week maintenance period to a one-week maintenance period, or vice versa. In certain instances, depository institutions that become eligible to shift to a quarterly instead of weekly reporting frequency elect to remain at the higher reporting frequency in order to maintain the flexibility of satisfying reserve requirements over a two-week maintenance period instead of a one-week maintenance period.

Under the Board's proposal, all depository institutions would be subject to a two-week maintenance period. This proposal would benefit depository institutions, Reserve Banks, and the Board in several ways. It would (1) Provide greater flexibility to depository institutions that currently satisfy reserve balance requirements over a one-week maintenance period; (2) reduce unnecessary complexity in the existing maintenance period structure; (3) reduce administrative and operational costs for depository institutions that may otherwise have had to change maintenance periods when deposit reporting categories (and therefore length of maintenance period) changed; and (4) reduce the operational and administrative cost for Reserve Banks and the Board by eliminating business processes and controls associated with maintaining two maintenance periods.

The creation of a common two-week maintenance period would not impede the conduct of monetary policy. Indeed, it is likely that the two-week maintenance period would enable those depository institutions currently subject to a one-week maintenance period to accommodate more easily unexpected conditions in the Federal funds market because of the longer period of time over which they would be able to manage their reserve positions.

The Board's proposal would not increase the reporting burden on depository institutions that currently have a two-week maintenance period. In addition, for those depository institutions mentioned above that elect

[5] 12 CFR 204.5(b) (maintenance periods). Prior to 1984, all depository institutions satisfied their reserve requirements using a common maintenance period of one week with a lag (''lagged reserve requirements''). Under lagged reserve requirements, the amount of reserves required to be maintained over the maintenance period was calculated based on deposit levels reported during a previous time period. In 1984, however, the Federal Reserve shifted to a framework of contemporaneous reserve requirements. Under contemporaneous reserve requirements, the deposit reporting period and the reserve maintenance period for depository institutions that reported their deposits weekly overlapped significantly. At that time, the Board lengthened the maintenance period for these depository institutions to two weeks in order to provide additional flexibility in meeting reserve requirements. In 1998, the Board returned to the lagged reserve requirements framework, but there was no corresponding change back to a common weekly maintenance period. Accordingly, since 1998, depository institutions that report their deposits weekly have continued to have a two-week maintenance period, while quarterly reporters have continued to have a one-week maintenance period.

[6] 12 U.S.C. 248(a) (authorizing the Board to require reports of liabilities and assets from depository institutions to enable the Board to conduct monetary policy).

[7] The exemption amount is the amount of an institution's reservable liabilities that is subject to a zero-percent reserve requirement. Cf. 12 CFR 204.4(f) (setting forth exemption amount).

to remain weekly reporters to maintain the flexibility of satisfying reserve requirements over a two-week maintenance period instead of a one-week maintenance period, the burden could be reduced, as these institutions could move to a quarterly reporting frequency and still maintain the flexibility of satisfying reserve requirements over a two-week maintenance period. Depository institutions that currently have a one-week maintenance period would have greater flexibility to manage reserve balances over a longer time period; it would not be necessary for such depository institutions to change their internal systems, as they could continue to satisfy their requirement weekly, if desired, within the two-week maintenance period.

Implications for Deposit Data Reporting

For depository institutions that report their deposits weekly, the relationship between the weekly reporting periods and the two-week maintenance period would be maintained. For depository institutions that report their deposits quarterly, the quarterly reporting periods will not change but a new relationship is being proposed to link these quarterly reporting periods to two-week maintenance periods.[8] The Board proposes that each quarterly report be used to calculate the reserve requirement for an interval of either six or seven consecutive two-week maintenance periods, depending on when the interval begins and ends. The interval will begin on the fourth Thursday following the end of each quarterly reporting period if that Thursday is the first day of a two-week maintenance period. If the fourth Thursday following the end of a quarterly reporting period is not the first day of a two-week maintenance period, then the interval will begin on the fifth Thursday following the end of the quarterly reporting period. The interval will end on the fourth Wednesday following the end of the subsequent quarterly reporting period if that Wednesday is the last day of a two-week maintenance period. If the fourth Wednesday following the end of the subsequent quarterly reporting period is not the last day of a two-week maintenance period, then the interval will conclude on the fifth Wednesday following the end of the subsequent quarterly reporting period.

The Board seeks comment on the costs and benefits associated with the proposal to create a common two-week maintenance period. The Board also seeks comment on whether there may be a particular benefit to a one-week common maintenance period rather than the proposed two-week common maintenance period. The Board further seeks comment on possible operational difficulties in transitioning to a two-week maintenance period for those depository institutions that currently have a one-week maintenance period.

2. Create a Penalty-Free Band Around Reserve Balance Requirements in Place of Carryover and Routine Penalty Waivers

Currently, Regulation D requires a depository institution to satisfy its reserve balance requirement on average over that depository institution's maintenance period. A depository institution that has a modest deficiency in its balance maintained to satisfy the reserve balance requirement over a given maintenance period (that is, the institution has maintained on average over the maintenance period a balance that is lower than the amount of its reserve balance requirement) is currently allowed to make up that deficiency in the subsequent maintenance period by holding a higher level of balances.[9] Similarly, a depository institution that has a modest excess of balances maintained to satisfy its reserve balance requirement over a maintenance period is allowed to use that excess to satisfy its reserve balance requirement in the next maintenance period, thereby permitting it to hold a lower average balance over the next maintenance period. The ability to carry a deficiency or excess from one maintenance period over to the next is referred to as ''carryover.''

Carryover was designed to provide depository institutions flexibility in satisfying their reserve balance requirements. Specifically, carryover permits a depository institution to utilize a portion of its excess balances from the current period to satisfy reserve requirements in the subsequent period and thereby avoid having to sell excess funds into the Federal funds market in the event it has more balances than it needs to satisfy its reserve balance requirement. Similarly, within limits, carryover allows a depository institution that does not have sufficient balances to satisfy its reserve balance requirement in the current period to meet a portion of that requirement in the subsequent period and thereby avoid having to increase borrowings in the Federal funds market to avoid a current period deficiency. Either one of these situations could produce sharp swings in market interest rates. Because carryover allows depository institutions to apply one maintenance period's excess or deficiency to the subsequent maintenance period, carryover necessarily links one maintenance period to its successor. As a result, one generally cannot determine for a given maintenance period whether a depository institution has satisfied its reserve balance requirement, or is in an excess or deficient position, until the completion of the subsequent maintenance period. Consequently, Reserve Banks must delay the payment of interest on eligible institutions' balances for at least one maintenance period, in order to calculate the amount and the type of an institution's balances.

Regulation D currently authorizes Reserve Banks to assess charges against depository institutions that fail to satisfy their reserve balance requirements.[10] Regulation D also authorizes Reserve Banks to waive the imposition of these charges except when the deficiency ''arises out of a depository institution's gross negligence or conduct that is inconsistent with the principles and purposes of reserve requirements.'' [11] Regulation D further provides that these ''routine penalty waivers'' are based on ''an evaluation of the circumstances in each individual case and the depository institution's reserve maintenance record.'' [12] Prior to 2008, reserve balance requirements imposed an implicit tax on depository institutions because it forced depository institutions to hold non-interest-bearing balances at Reserve Banks when those funds could have been invested elsewhere for a return. Because of this implicit tax, depository institutions had an incentive to keep the level of the balances in their Reserve Bank accounts as close as possible to their reserve balance requirements. The ''routine waiver'' provision of Regulation D, permitting Reserve Banks to waive the charge for small or infrequent deficiencies, was designed to avoid punishing depository institutions that generally meet their reserve balance requirements.[13]

[8] The Board currently provides quarterly reporters with reserve maintenance calendars that link quarterly reporting periods to a group of one-week maintenance periods. *See http://www.frbservices.org/centralbank/reservescentral/index.html#rmc.* If the Board adopts the proposed amendments to Regulation D in final form, these reserve maintenance calendars will be updated accordingly.

[9] 12 CFR 204.6(a).

[10] 12 CFR 204.6(a).

[11] 12 CFR 204.6(b).

[12] *Id.*

[13] Infrequent deficiencies cannot exceed a certain percentage of the depository institution's required reserves and can only occur once during a two-year period.

The Board is proposing to create a penalty-free band around each depository institution's reserve balance requirement and to eliminate the carryover and routine waiver provisions of Regulation D. Under the proposal, the top of the penalty-free band would be defined as an amount equal to an institution's reserve balance requirement plus a dollar amount prescribed by the Board. Similarly, the proposal would define the bottom of the penalty-free band as an amount equal to an institution's reserve balance requirement less a dollar amount prescribed by the Board. The dollar amount used to set the top and bottom of the penalty-free band could be set as a fixed dollar amount, specified as a percent of an institution's reserve balance requirement, or as a combination of a fixed dollar amount and a percent of an institution's reserve balance requirement. The dollar amounts prescribed by the Board to determine the top and bottom of the penalty-free band may differ from each other.

A depository institution that maintains balances that exceeded the reserve balance requirement, but fell within the band, would be remunerated at the interest rate paid on balances maintained to satisfy the reserve balance requirement. Balances that exceeded the top of the penalty-free band would be remunerated at the interest rate paid on excess balances.[14] A depository institution that maintains balances below its reserve balance requirement would not be assessed a deficiency charge unless the balances fell below the bottom of the penalty-free band. The proposal would define a deficiency as the bottom of the penalty-free band less the average balance held in an account at a Reserve Bank by or on behalf of an institution over a maintenance period. Under the proposal, Reserve Banks could pay interest on all balances immediately following the close of a maintenance period.

The creation of a penalty-free band in place of carryover and routine penalty waivers would not impede the conduct of monetary policy. The administration of a penalty-free band would be more straightforward than the complex rules surrounding the application of carryover and routine penalty waivers. The elimination of these features will make reserve administration more efficient and less administratively burdensome and operationally complex for depository institutions, Reserve Banks, and the Board, thereby supporting the effective implementation of monetary policy. Reserve Banks would, however, retain the authority to waive charges for deficiencies based on an evaluation of the circumstances in each individual case.

Currently, the Reserve Banks pay interest on balances maintained to satisfy reserve balance requirements at a rate designed to effectively eliminate the opportunity cost of holding such balances. In general, any interest rate paid on balances maintained to satisfy reserve balance requirements reduces the opportunity cost of holding those balances. If the interest rate set on balances used to satisfy reserve balance requirements effectively eliminates the opportunity cost of holding those balances, most depository institutions should in principle be willing to hold any level of balances within the penalty-free band. A depository institution could choose to hold an amount of balances slightly below the reserve balance requirement and lend the difference in the market; however, the additional interest earned would be approximately offset by the reduced earnings from the Reserve Banks. Similarly, a depository institution could choose to hold an amount slightly higher than the reserve balance requirement and earn a greater amount of interest from its balances at the Reserve Bank. This higher amount of interest earned would be comparable to the foregone return of investing these funds in the market.

The Board proposes to set the width of the penalty-free band to approximate the flexibility in meeting reserve requirements that carryover now provides. Under Regulation D currently, the amount an institution can use for carryover into a subsequent maintenance period is calculated as the greater of $50,000 or 4 percent of a depository institution's total reserve requirement.[15] The total reserve requirement is the amount satisfied with both an institution's vault cash and, if its vault cash is insufficient to satisfy the reserve requirement, an institution's reserve balance requirement. The proposed penalty-free band would be based on the reserve balance requirement, not the total reserve requirement. For purposes of implementing monetary policy and controlling the Federal funds rate, reserve balance requirements are a more relevant quantity to consider than required reserves. On average, reserve balance requirements are just under half of total reserve requirements, that is, depository institutions generally satisfy slightly less than half of reserve requirements with reserve balances. The flexibility provided by the 4 percent carryover provision, when expressed in terms of reserve balance requirements, would equate to roughly 10 percent of the reserve balance requirement for a typical depository institution. Establishing a $50,000 minimum for the penalty-free band would preserve that degree of flexibility for institutions with relatively low reserve balance requirements. Therefore, the Board proposes setting the dollar amount used to establish the top and bottom of the penalty-free band at the greater of $50,000 or 10 percent of a depository institution's reserve balance requirement. For pass-through correspondents, the Board proposes setting the dollar amount used to establish the top and bottom of the penalty-free band at an amount that is equal to the greater of $50,000 or 10 percent of the aggregate reserve balance requirement of the correspondent (if any) and all of its respondents.

The Board expects that, if set this way, the width of the penalty-free band would, for a typical depository institution, approximate the flexibility in meeting reserve requirements that carryover currently provides. The Board also expects, however, that there will be depository institutions that are afforded less and more flexibility under the proposal than they are currently afforded under the carryover provision. For example, institutions that have reserve balance requirements that are almost as large as their reserve requirement will have greater flexibility under the proposal because their penalty-free band will be bigger than their current carryover provision. Institutions with very small reserve balance requirements relative to their reserve requirements, on the other hand, will have less flexibility because their penalty-free band will be smaller than their current carryover provision. The Board seeks comment on what factors the Board should consider in determining the appropriate size of the penalty-free band, expressed either in dollars or as a percentage, around a reserve balance requirement.

3. Discontinue As-of Adjustments Related to Deposit Revisions and Replace All Other As-of Adjustments With Direct Compensation

As-of adjustments are currently used to offset the effect of errors caused by the Federal Reserve and depository institutions, including deposit reporting

[14] Under the proposal, the definition of ''excess balance'' would be amended to mean the average balance held in an account at a Federal Reserve Bank by or on behalf of an institution over a reserve maintenance period that exceeds the top of the penalty-free band.

[15] 12 CFR 204.5(e).

errors, or to recover float incurred by an institution.

As-of Adjustments for Deposit Revisions

A depository institution is required to submit revisions to past deposit reports to correct for reporting errors. When those revisions result in a change in the depository institution's reserve balance requirement, an as-of adjustment is used to correct the depository institution's level of balances maintained. For example, if a reserve balance requirement for a given period is revised upwards, the as-of adjustment is used so that the depository institution must hold a greater level of balances in a future maintenance period in order to meet its reserve balance requirement.

The administration of as-of adjustments for deposit revisions imposes a burden on depository institutions, Reserve Banks, and the Board. Moreover, the Board believes that as-of adjustments for deposit revisions are not necessary when the payment of interest on reserve balances reduces or largely offsets the opportunity cost of holding balances to satisfy reserve requirements. Consequently, the Board is proposing to eliminate the use of as-of adjustments for deposit revisions. Reports of deposits will continue to be used for the calculation and publication of the monetary aggregates, and therefore revisions to deposit reports would still be required to correct errors.

The payment of interest on balances maintained to satisfy reserve balance requirements essentially eliminates the need for as-of adjustments for deposit revisions. If a revision to a depository institution's reservable liabilities lowers its reserve balance requirement, the depository institution should have held a lower level of balances to satisfy the lower reserve balance requirement prescribed by the revised deposit data. Before the payment of interest on reserves, holding a lower level of such balances would in principle allow the institution to earn additional interest income by lending out the balances. As-of adjustments in this case effectively compensated the depository institution for this loss of investment income by allowing the institution to hold lower reserve balances in a subsequent period. However, because depository institutions are currently paid interest on those balances at a rate approximately equal to the rate of return that can be earned by lending out reserve balances, the depository institution does not incur a loss as a result of the lower reserve requirement after the fact and thus there is no need for an as-of adjustment. Conversely, if a revision to a depository institution's reservable liabilities increases its reserve balance requirement, the depository institution should have held a higher level of balances to satisfy the higher reserve balance requirement prescribed by the revised deposit data. Holding the higher level of balances requires the institution to forego the return it earned on lending those funds. Before the payment of interest on reserves, as-of adjustments effectively required the depository institution to surrender the interest income gained from lending out balances by requiring the institution to maintain higher balances in a subsequent period. But because the Reserve Banks are currently paying interest on balances maintained to satisfy reserve balance requirements at a rate designed to effectively eliminate this opportunity cost, the depository institution does not benefit from holding lower balances than required based on the revised deposit data. As a result, there is again no need for an as-of adjustment.

All As-of Adjustments Other Than Those Related to Deposit Revisions

As-of adjustments can also be used for a number of other purposes including, but not limited to, the correction of transaction errors, the recovery of float, and penalizing an institution for a reserve deficiency in lieu of assessing monetary charges. An as-of adjustment for a transaction-based error corrects the average level of balances maintained by the depository institution to the level that would have resulted had the error not occurred. Reserve Banks also issue as-of adjustments to recover float that arises from an institution's request to defer check and ACH charges for days in which the institution is closed. Currently, a float pricing as-of adjustment or an explicit billing charge to the institution's account is used to compensate the Reserve Bank for the float created. In addition, Reserve Banks have the ability to use as-of adjustments to penalize an institution for a reserve deficiency rather than imposing monetary charges.

The Board is proposing that the income effects of all transaction-based errors be corrected through direct compensation (that is, either a debit or credit applied to an account to offset the effect of an error). For float payments stemming from temporary closings of institutions, the Board proposes that the recovery of float will be made through an explicit billing charge and not with the issuance of as-of adjustments. For as-of adjustments related to reserve deficiencies, the Board is proposing to amend section 204.6(a) of Regulation D to eliminate the ability to address reserve deficiencies in any manner besides the assessment of charges.

Consistent with these proposals, elsewhere in the **Federal Register** the Board is proposing conforming changes to the provisions in Regulation J that refer to as-of adjustments.

As with the other proposed simplifications, the Board believes that discontinuing as-of adjustments related to deposit revisions and replacing all other as-of adjustments with direct compensation does not affect the conduct of monetary policy. The Board is proposing to pay or charge an institution based on the Federal funds rate. As a matter of current practice, for other instances where Reserve Banks directly compensate depository institutions, the amount compensated is based on the Federal funds rate. The Board requests comment on whether use of the Federal funds rate for the calculation of direct compensation is appropriate, and if not, the rate that the Board should use.[16]

4. Eliminate the Contractual Clearing Balance Program

Currently, a depository institution may voluntarily agree with a Reserve Bank to maintain a level of balances in excess of the amount necessary to satisfy its reserve balance requirement. This program, known as the contractual clearing balance program, allows a Reserve Bank and a depository institution to agree on a specific balance, known as a contractual clearing balance, that the depository institution will hold.[17] The actual amount that a depository institution holds to comply with this agreement is known as a clearing balance.[18] Under the contractual clearing balance program, Reserve Banks do not pay explicit interest on clearing balances. Instead, clearing balances generate earnings credits that a depository institution may then use to pay for Reserve Bank priced services.

Clearing balances were also initially implemented to provide depository institutions that have low reserve balance requirements with an incentive to hold a level of balances that will facilitate clearing of payments and reduce the risk of an overdraft in their Reserve Bank accounts. Earnings credits

[16] With respect to Fedwire funds transfers, § 210.32(b)(1)(ii) of Regulation J and Article 4A–506(b) provide that if the amount of interest is not determined by an agreement or rule, the applicable Federal funds rate would apply.

[17] 12 CFR 204.2(x) (definition of contractual clearing balance).

[18] 12 CFR 204.2(v) (definition of clearing balance).

earned on clearing balances can be used only to offset Federal Reserve priced services fees within a 52-week period, after which the credits expire. The interest rate used to calculate earnings credits is currently 80 percent of the 13-week moving average of the yield on the three-month Treasury bill.

The contractual clearing balance program was implemented to replicate similar programs in the private sector. At that time, neither Reserve Banks nor depository institutions were authorized to pay explicit interest on balances maintained by eligible institutions. The contractual clearing balance program permitted Reserve Banks to compensate institutions in the form of earnings credits. The contractual clearing balance program has also played a role in the pricing of Reserve Bank services. Specifically, the level of clearing balances is a significant factor in establishing the amount of imputed costs that must be recovered by the Reserve Bank priced services fees, as required by the Monetary Control Act of 1980.[19]

Currently, balances maintained to satisfy reserve balance requirements and excess balances receive explicit interest, but clearing balances do not. Reserve Banks currently pay explicit interest on excess balances at a rate that is higher than the rate of implicit interest currently paid on clearing balances. In addition, a depository institution can use the explicit interest it receives on balances held at a Reserve Bank for any purpose, including defraying the costs of using Federal Reserve priced services. As a result, a depository institution today that holds balances in excess of the amount necessary to satisfy its reserve balance requirement would receive a higher return by simply reducing its contractual clearing balance to zero, redesignating its clearing balances as excess balances, and receiving explicit interest on those balances at a higher rate. Consistent with this interest rate differential, there has been a marked decrease in the aggregate quantity of clearing balances maintained by depository institutions since the introduction of the payment of explicit interest on Reserve Bank account balances. Between the October 2008 implementation of the payment of interest on reserve balances and June 2011, the total level of clearing balances held by depository institutions has decreased approximately $3.8 billion, from $6.5 billion to $2.7 billion.

The elimination of the contractual clearing balance program would enhance the Federal Reserve's ability to carry out monetary policy by eliminating the complexities associated with maintaining different balance requirements for different kinds of balances and different kinds and levels of interest rates (explicit and implicit).[20] Since 2008, the explicit interest rates paid on balances maintained to satisfy the reserve balance requirement and excess balances have become an important tool for the conduct of monetary policy. Maintaining a separate implicit interest rate paid on clearing balances under these circumstances could interfere with clear communication of the stance of monetary policy.

Under the proposal, the Board would amend Regulation D to remove the definitions of ''clearing balance,'' ''clearing balance allowance,'' and ''contractual clearing balance.'' The proposal would also remove references to clearing balances and contractual clearing balances elsewhere in Regulation D.

With the elimination of the contractual clearing balance program, contractual clearing balance agreements would be terminated and Reserve Banks would no longer issue earnings credits. Earnings credits issued prior to the effective date of the termination would not be affected by this proposal and would expire 52 weeks from their issue date if they are not used. The proposed elimination of the contractual clearing balance program may affect some depository institutions' internal budgeting procedures, because they would need to begin paying for Reserve Bank priced services explicitly, rather than implicitly through the use of earnings credits. Also, a small number of institutions, such as the Federal Home Loan Banks, are not eligible to earn explicit interest on balances in their Reserve Bank accounts, but are eligible to receive earnings credits under the contractual clearing balance program. These institutions would lose the implicit interest from these balances to pay for Reserve Bank services.

Because the level of clearing balances is a significant factor in establishing the amount of imputed costs that must be recovered by Reserve Bank priced services fees, the Board has been considering a revised methodology for imputing those costs as clearing balances have declined.[21] In March 2009, the Board requested comment on a proposal to replace the current ''correspondent bank model'' for imputing these costs with a model based on publicly traded firms (''publicly traded firm model'' or ''PTF model'').[22] The PTF model proposed in 2009 would accommodate the proposed elimination of clearing balances and would also recognize the shift in priced services' financial characteristics and competitors away from correspondent banks. The PTF model would instead compare the Federal Reserve's priced services to the entire universe of U.S. publicly traded firms. Under the PTF model, the imputed elements of priced services, such as the capital structure and financing and tax rates, would be based on data for the U.S. market as a whole rather than banking institutions. The Board is currently considering the comments received on the proposed PTF model but has maintained the correspondent banking model for 2010 and 2011 because significant levels of clearing balances continue to exist.[23]

The Board seeks comment on all aspects of eliminating the contractual clearing balance program. The Board specifically seeks comments on the following issues related to the effect of eliminating the program on imputing costs to be recovered by Federal Reserve priced services:

1. Would eliminating the contractual clearing balance program materially diminish the value of Federal Reserve priced services? If so, how?

2. Are there any operational difficulties related to the elimination of the contractual clearing balance program as proposed? If so, how long is needed to prepare for the elimination of the program?

3. In order to determine the imputed return on equity (profit) of Federal Reserve priced services, an equity financing rate is applied to the level of equity on the priced services balance sheet. Under the proposed PTF model, the imputed equity level would be computed based on the priced services net funding need (assets less liabilities). Without the clearing balance liabilities and the associated imputed

[19] 12 U.S.C. 248a(c)(3).

[20] The elimination of the contractual clearing balance program would not have any effect on a Reserve Bank's ability to compel account holders to maintain a minimum level of balances in order for the Reserve Bank to protect itself from risk. *See* Reserve Bank Operating Circulars at *http://www.frbservices.org/regulations/operating_circulars.html.*

[21] The Monetary Control Act of 1980 requires that the Board set fees for priced services provided to depository institutions by the Reserve Banks to recover all direct and indirect costs of providing these services over the long run. These costs include those actually incurred as well as imputed costs, which include financing costs, taxes, and certain other expenses, as well as the return on equity (profit) that would have been earned by a private-sector provider. 12 U.S.C. 248a(c)(3).

[22] 74 FR 15481 (April 6, 2009).

[23] *See* 74 FR 57472 (November 6, 2009) and 75 FR 67734 (November 3, 2010).

investments, the net priced services' funding need may be very low when the level of assets associated with priced services assets closely matches the level of liabilities. This, in turn, would generate a very low level of imputed equity relative to assets (*i.e.,* less than 5 percent of total assets).[24] A lower equity-to-assets ratio under the PTF model than the FDIC-required amount of 5 percent of total assets under the current correspondent bank model would make the priced services less comparable to the market as a whole.[25] The Board seeks comment on whether it should establish a minimum imputed equity level. If so, the Board seeks comment on the approach it should use to ensure the minimum imputed equity, such as adjusting the debt-to-equity mix from the model (decreasing debt and increasing equity) and/or imputing additional equity.[26] The Board also requests comment on whether it should use the FDIC minimum equity requirements for commercial banks that are used in the current correspondent bank model or some other basis for establishing the minimum level.

4. The proposed PTF model reflected, in part, the recognition that the financial characteristics of the Reserve Banks' priced services and its competitors were becoming less comparable to banking organizations. Even with the elimination of clearing balances, the Reserve Banks' priced services would still incur (and include in its prices) the costs and benefits related to float. Float occurs when the Reserve Banks debit an institution's account for a transaction on a different day than they credit the account of the institution receiving the funds. Reserve Bank float currently represents approximately one-third of the priced services balance sheet. Typically, depository institutions are more likely to reflect large amounts of float, either debit or credit, on their balance sheets than are other types of businesses; however, these data are not separately reported. Nonbank payment processing firms generate some float, but those amounts are generally a much smaller percentage of their balance sheets than is currently the case for the Reserve Banks' priced services balance sheet. The Board seeks comment on whether the correspondent bank model should be replaced only once the amount of float generated by priced services is a much smaller proportion of the Reserve Banks' imputed balance sheet.

5. Effective Dates

The Board proposes to eliminate the contractual clearing balance program and the use of as-of adjustments no earlier than the first quarter of 2012 and to implement a common reserves maintenance period and the penalty-free band around reserve balance requirements no earlier than the third quarter of 2012. The Board requests comment on whether the proposed effective dates are appropriate. The Board specifically seeks comment on time that depository institutions will need to effect the changes in their systems to adapt to these changes and whether the cost of adapting to these changes will be material.

III. Initial Regulatory Flexibility Analysis

Congress enacted the Regulatory Flexibility Act (the ''RFA'') (5 U.S.C. 601 *et seq.*) to address concerns related to the effects of agency rules on small entities. The RFA requires agencies either to provide an initial regulatory flexibility analysis with a proposed rule or to certify that the proposed rule will not have a significant economic impact on a substantial number of small entities. In accordance with section 3(a) of the RFA, the Board has reviewed the proposed regulation, which would apply to all depository institutions. Based on current information, the Board believes that although a significant number of ''small banking organizations'' would be affected by the rule, the rule would not have a significant economic impact on these small entities because the amendments are intended to decrease costs (5 U.S.C. 605(b)). Nonetheless, the Board has prepared an initial regulatory flexibility analysis in accordance with 5 U.S.C. 603 in order for the Board to seek comment on the potential impact of the proposed rule on small entities. The Board will, if necessary, conduct a final regulatory flexibility analysis after consideration of comments received during the public comment period.

1. *Statement of the need for, objectives of, and legal basis for, the proposed rule.* The Board is proposing to amend Regulation D to simplify reserves administration. Section 19 of the Federal Reserve Act authorizes the Board to impose reserve requirements on certain deposits and other liabilities of depository institutions solely for the purposes of implementing monetary policy. The Board's Regulation D implements section 19 of the Act. The Board believes that the proposed amendments to Regulation D will reduce the administrative and operational costs associated with reserve requirements for depository institutions.

2. *Small entities affected by the proposed rule.* The proposed rule would affect all depository institutions. Pursuant to regulations issued by the Small Business Administration (the ''SBA'') (13 CFR 121.201), a ''small banking organization'' includes a depository institution with $175 million or less in total assets. Based on data reported as of March 31, 2011, the Board believes that there are approximately 10,723 small depository institutions. Out of these small depository institutions, there are approximately 3,088 small depository institutions that satisfy their reserve balance requirement on a one-week maintenance period; approximately 1,927 small depository institutions with contractual clearing balances; and approximately 108 small depository institutions that received at least one as-of adjustment over the first five months of 2011.

3. *Projected reporting, recordkeeping, and other compliance requirements.* The proposed rule imposes certain compliance requirements on small depository institutions. Under proposed section 204.5(b)(2), small depository institutions that satisfy their reserve balance requirement on a one-week maintenance period (approximately 3,088) would be subject to a two-week maintenance period. As noted above, it would presumably not be necessary, however, for such a depository institution to change its internal systems, as it could continue to satisfy its requirement weekly, within the two-week maintenance period. The proposed rules would also eliminate the contractual clearing balance program, currently used by approximately 1,927 small depository institutions. Although the contractual clearing program would be eliminated, the Board does not anticipate that small depository institutions would be negatively affected because small depository institutions would receive explicit interest on excess balances instead of earnings credits on clearing balances. Small depository institutions could then use this explicit interest to pay for Reserve Bank priced services or for other purposes. In addition, the proposed rule would eliminate the use of as-of adjustments for deposit revisions. The Board seeks information and comment on any costs, including

[24] If liabilities exceed assets, the equity-to-assets ratio could be negative.

[25] For example, for 2003–2008, the average equity as a percent of total assets for the market as a whole was 18 percent. The priced services imputed equity represents its market capitalization as a going concern entity.

[26] Equity imputed in excess of the priced services funding need would be offset by an increase in imputed investments and would be invested in a risk-free investment that matches the time horizon of the funding need (*i.e.* one-year Treasury bond).

those costs associated with changes to internal systems, that would arise from the application of the proposed rule.

4. *Identification of duplicative, overlapping, or conflicting Federal rules.* The Board does not believe that any Federal rules duplicate, overlap, or conflict with the proposed rule. The Board is proposing in a separate proposal to amend the Board's Regulation J to remove references to as-of adjustments in order to conform that regulation to this proposal. The Board seeks comment regarding any other statutes or regulations that would duplicate, overlap, or conflict with the proposed rule.

5. *Significant alternatives to the proposed rule.* The Board is unaware of any significant alternatives to the proposed rule that accomplish the stated objectives of the Board to simplify the administration of reserve requirements. The Board requests comment on whether there are additional ways to reduce the burden associated with the administration of reserve requirements on small entities associated with this proposed rule.

IV. Paperwork Reduction Act Analysis

In accordance with the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3506; 5 CFR part 1320 appendix A.1), the Board reviewed the proposed rule under the authority delegated to the Board by the Office of Management and Budget (OMB). Although the mandatory data collected on the deposits reporting forms [27] are used by the Federal Reserve for administering Regulation D and for constructing, analyzing, and monitoring the monetary and reserve aggregates none of the revisions proposed in this rulemaking would change the deposits reporting forms. No collections of information pursuant to the PRA are contained in this proposed rule.

Comments on this analysis should be sent to Cynthia Ayouch, Federal Reserve Board Clearance Officer, Division of Research and Statistics, Mail Stop 95–A, Board of Governors of the Federal Reserve System, Washington, DC 20551, with copies of such comments sent to the Office of Management and Budget, Paperwork Reduction Project (Regulation D), Washington, DC 20503.

List of Subjects in 12 CFR Part 204

Banks, banking, Reporting and recordkeeping requirements.

[27] Report of Transaction Accounts, Other Deposits and Vault Cash (FR 2900; OMB No. 7100–0087), Annual Report of Total Deposits and Reservable Liabilities (FR 2910a; OMB No. 7100–0175), Report of Foreign (Non-U.S.) Currency Deposits (FR 2915; OMB No. 7100–0237), and Allocation of Low Reserve Tranche and Reservable Liabilities Exemption (FR 2930; OMB No. 7100–0088).

For the reasons stated in the preamble, the Board proposes to amend 12 CFR part 204 as follows:

PART 204—RESERVE REQUIREMENTS OF DEPOSITORY INSTITUTIONS (REGULATION D)

1. The authority citation for part 204 continues to read as follows:

Authority: 12 U.S.C. 248(a), 248(c), 461, 601, 611, and 3105.

2. In § 204.1, revise paragraph (b) to read as follows:

§ 204.1 Authority, purpose and scope.

* * * * *

(b) *Purpose.* This part relates to reserve requirements imposed on depository institutions for the purpose of facilitating the implementation of monetary policy by the Federal Reserve System.

* * * * *

3. In § 204.2:

A. Remove and reserve paragraphs (v) through (x);

B. Revise paragraphs (z) and (bb); and

C. Add paragraphs (ee) through (hh).

The additions and revisions read as follows:

§ 204.2 Definitions.

* * * * *

(z) *Excess balance* means the average balance held in an account at a Federal Reserve Bank by or on behalf of an institution over a reserve maintenance period that exceeds the top of the penalty-free band.

* * * * *

(bb) Balance maintained to satisfy the reserve balance requirement means the average balance held in an account at a Federal Reserve Bank by or on behalf of an institution over a reserve maintenance period to satisfy the reserve balance requirement of this part.

* * * * *

(ee) *Reserve balance requirement* means the balance that a depository institution is required to maintain on average over a reserve maintenance period in an account at a Federal Reserve Bank if vault cash does not fully satisfy the depository institution's reserve requirement imposed by this part.

(ff) *Deficiency* means the bottom of the penalty-free band less the average balance held in an account at a Federal Reserve Bank by or on behalf of an institution over a reserve maintenance period.

(gg) *Top of the penalty-free band* means an amount equal to an institution's reserve balance requirement plus an amount that is the greater of 10 percent of the institution's reserve balance requirement or $50,000. The top of the penalty-free band for a pass-through correspondent is an amount equal to the aggregate reserve balance requirement of the correspondent (if any) and all of its respondents plus an amount that is the greater of 10 percent of that aggregate reserve balance requirement or $50,000.

(hh) *Bottom of the penalty-free band* means an amount equal to an institution's reserve balance requirement less an amount that is the greater of 10 percent of the institution's reserve balance requirement or $50,000. The bottom of the penalty-free band for a pass-through correspondent is an amount equal to the aggregate reserve balance requirement of the correspondent (if any) and all of its respondents less an amount that is the greater of 10 percent of that aggregate reserve balance requirement or $50,000.

4. In § 204.4 revise paragraphs (d) and (e), and the introductory text of paragraph (f), to read as follows:

§ 204.4 Computation of required reserves.

* * * * *

(d) For institutions that file a report of deposits weekly, reserve requirements are computed on the basis of the institution's daily average balances of deposits and Eurocurrency liabilities during a 14-day computation period ending every second Monday.

(e) For institutions that file a report of deposits quarterly, reserve requirements are computed on the basis of the institution's daily average balances of deposits and Eurocurrency liabilities during the 7-day computation period that begins on the third Tuesday of March, June, September, and December.

(f) For all depository institutions, Edge Agreement corporations, and United States branches and agencies of foreign banks, reserve requirements are computed by applying the reserve requirement ratios below to net transaction accounts, nonpersonal time deposits, and Eurocurrency liabilities of the institution during the computation period.

* * * * *

5. In § 204.5:

A. Revise paragraphs (a)(1), (b), (c), and (d); and

B. Remove paragraph (e).

The revisions read as follows:

§ 204.5 Maintenance of required reserves.

(a)(1) A depository institution, a U.S. branch or agency of a foreign bank, and an Edge or Agreement corporation shall satisfy reserve requirements by maintaining vault cash and, if vault cash does not fully satisfy the institution's

reserve requirement, in the form of a balance maintained—

(i) In the institution's account at the Federal Reserve Bank in the Federal Reserve District in which the institution is located, or

(ii) With a pass-through correspondent in accordance with paragraph (d) of this section.

* * * * *

(b)(1) For institutions that file a report of deposits weekly, the balances maintained to satisfy reserve balance requirements shall be maintained during a 14-day maintenance period that begins on the third Thursday following the end of a given computation period.

(2) For institutions that file a report of deposits quarterly, the balances maintained to satisfy reserve balance requirements shall be maintained during an interval of either six or seven consecutive 14-day maintenance periods, depending on when the interval begins and ends. The interval will begin on the fourth Thursday following the end of each quarterly reporting period if that Thursday is the first day of a 14-day maintenance period. If the fourth Thursday following the end of a quarterly reporting period is not the first day of a 14-day maintenance period, then the interval will begin on the fifth Thursday following the end of the quarterly reporting period. The interval will end on the fourth Wednesday following the end of the subsequent quarterly reporting period if that Wednesday is the last day of a 14-day maintenance period. If the fourth Wednesday following the end of the subsequent quarterly reporting period is not the last day of a 14-day maintenance period, then the interval will conclude on the fifth Wednesday following the end of the subsequent quarterly reporting period.

(c) Cash items forwarded to a Federal Reserve Bank for collection and credit are not included in an institution's balance maintained to satisfy its reserve balance requirement until the expiration of the time specified in the appropriate time schedule established under Regulation J, ''Collection of Checks and Other Items by Federal Reserve Banks and Funds Transfers Through Fedwire'' (12 CFR part 210). If a depository institution draws against items before that time, the charge will be made to its account if the balance is sufficient to pay it; any resulting deficiency in balances maintained to satisfy the institution's reserve balance requirement will be subject to the penalties provided by law and to the deficiency charges provided by this part. However, the Federal Reserve Bank may, at its discretion, refuse to permit the withdrawal or other use of credit given in an account for any time for which the Federal Reserve Bank has not received payment in actually and finally collected funds.

(d)(1) A depository institution, a U.S. branch or agency of a foreign bank, or an Edge or Agreement corporation with a reserve balance requirement (''respondent'') may select only one pass-through correspondent under this section, unless otherwise permitted by the Federal Reserve Bank in whose District the respondent is located. Eligible pass-through correspondents are Federal Home Loan Banks, the National Credit Union Administration Central Liquidity Facility, and depository institutions, U.S. branches or agencies of foreign banks, and Edge and Agreement corporations that maintain balances to satisfy their own reserve balance requirements, which may be zero, in an account at a Federal Reserve Bank. In addition, the Board reserves the right to permit other institutions, on a case-by-case basis, to serve as pass-through correspondents.

(2) Respondents or correspondents may institute, terminate, or change pass-through correspondent agreements by providing all documentation required for the establishment of the new agreement or termination of or change to the existing agreement to the Federal Reserve Banks involved within the time period specified by those Reserve Banks.

(3) Balances maintained to satisfy the reserve balance requirements of a correspondent's respondents shall be maintained, along with the balances maintained to satisfy the correspondent's reserve balance requirement (if any), in a single commingled account of the correspondent at the Federal Reserve Bank in whose District the correspondent is located. Balances maintained in the correspondent's account are the property of the correspondent and represent a liability of the Reserve Bank solely to the correspondent, regardless of whether the funds represent the balances maintained to satisfy the reserve balance requirement of a respondent.

(4)(i) A pass-through correspondent shall be responsible for maintaining balances to satisfy its own reserve balance requirement (if any) and the reserve balance requirements of all of its respondents. A charge for any deficiency in the correspondent's account will be imposed by the Reserve Bank on the correspondent maintaining the account.

(ii) Each correspondent is required to maintain detailed records for each of its respondents that permit Reserve Banks to determine whether the respondent has provided sufficient funds to the correspondent to satisfy the reserve balance requirement of the respondent. The correspondent shall maintain such records and make such reports as the Board or Reserve Bank may require in order to ensure the correspondent's compliance with its responsibilities under this section and shall make them available to the Board or Reserve Bank as required.

6. In § 204.6, revise the heading and revise paragraphs (a) and (b) to read as follows:

§ 204.6 Charges for deficiencies.

(a) Federal Reserve Banks are authorized to assess charges for deficiencies at a rate of 1 percentage point per year above the primary credit rate, as provided in § 201.51(a) of this chapter, in effect for borrowings from the Federal Reserve Bank on the first day of the calendar month in which the deficiencies occurred. Charges shall be assessed on the basis of daily average deficiencies during each maintenance period.

(b) Reserve Banks may waive the charges for deficiencies based on an evaluation of the circumstances in each individual case.

* * * * *

7. In § 204.10 revise paragraphs (b)(1), (b)(3), (c), (d)(3) and (e)(2) to read as follows:

§ 204.10 Payment of interest on balances.

* * * * *

(b)(1) For balances up to the top of the penalty-free band, at ¼ percent;

* * * * *

(3) For balances up to the top of the penalty-free band, excess balances, and term deposits, at any other rate or rates as determined by the Board from time to time, not to exceed the general level of short-term interest rates. For purposes of this subsection, ''short-term interest rates'' are rates on obligations with maturities of no more than one year, such as the primary credit rate and rates on term Federal funds, term repurchase agreements, commercial paper, term Eurodollar deposits, and other similar instruments.

(c) *Pass-through balances.* A pass-through correspondent that is an eligible institution may pass back to its respondent interest paid on balances maintained to satisfy the reserve balance requirement of that respondent. In the case of balances held by a pass-through

correspondent that is not an eligible institution, a Reserve Bank shall pay interest only on the balances maintained to satisfy the reserve balance requirement of one or more respondents up to the top of the penalty-free band, and the correspondent shall pass back to its respondents interest paid on balances in the correspondent's account.

(d) * * *

(3) Balances maintained in an excess balance account will not satisfy any institution's reserve balance requirement.

* * * * *

(e) * * *

(2) A term deposit will not satisfy any institution's reserve balance requirement.

* * * * *

By order of the Board of Governors of the Federal Reserve System, October 7, 2011.

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 2011–26770 Filed 10–17–11; 8:45 am]

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FEDERAL RESERVE SYSTEM

12 CFR Part 210

[Regulation J; Docket No. R–1434]

RIN 7100 AD 84

Collection of Checks and Other Items by Federal Reserve Banks and Funds Transfers Through Fedwire: Elimination of ''As-of Adjustments'' and Other Clarifications

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Notice of proposed rulemaking; request for public comment.

SUMMARY: The Board is requesting public comment on proposed amendments to Regulation J (Collection of Checks and Other Items by Federal Reserve Banks and Funds Transfers through Fedwire). The proposed changes would eliminate references to ''as-of adjustments'' consistent with the Board's proposed amendments to Regulation D to simplify reserves administration. The proposed amendments would also clarify that an institution's Administrative Reserve Bank is deemed to have accepted deposit of a check or other item even if the institution sends the item directly to another Federal Reserve Bank. The proposed amendments would further clarify that Regulation J continues to apply to a Fedwire funds transfer even if the funds transfer also meets the definition of ''remittance transfer'' under the Electronic Fund Transfer Act.

DATES: Comments must be submitted by December 19, 2011.

ADDRESSES: You may submit comments, identified by Docket No. R–1434 and RIN 7100 AD 84, by any of the following methods:

- *Agency Web Site: http://www.federalreserve.gov.* Follow the instructions for submitting comments at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm.*
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: regs.comments@federalreserve.gov.* Include the docket number in the subject line of the message.
- *Fax:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Jennifer J. Johnson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information.

Public comments may also be viewed electronically or in paper in Room MP–500 of the Board's Martin Building (20th and C Streets, NW.) between 9 a.m. and 5 p.m. on weekdays.

FOR FURTHER INFORMATION CONTACT: Kara Handzlik, Senior Attorney (202) 452–3852, Legal Division; Margaret Gillis DeBoer, Assistant Director (202) 452–3139, or Heather Wiggins, Senior Financial Analyst (202) 452–3674, Division of Monetary Affairs; or Joseph Baressi, Project Leader, Division of Reserve Bank Operations and Payment Systems (202) 452–3959; for users of Telecommunications Device for the Deaf (TDD) only, contact (202) 263–4869; Board of Governors of the Federal Reserve System, 20th and C Streets, NW., Washington, DC 20551.

SUPPLEMENTARY INFORMATION:

I. Background

Subpart A of Regulation J governs the collection of checks and other items by the Federal Reserve Banks (Reserve Banks), including the types of checks or other items that may be sent to Reserve Banks, the order in which they are deemed to be handled, and the related warranties and indemnities. Subpart B of Regulation J sets forth the terms and conditions under which Reserve Banks receive and deliver payment orders from and to depository institutions over the Reserve Banks' Fedwire® Funds Service (Fedwire).

The Board is proposing amendments to Regulation J that would eliminate references throughout Regulation J to a Reserve Bank's use of ''as-of adjustments.'' [1] These amendments are consistent with the Board's proposed amendments to Regulation D, published elsewhere in the **Federal Register**, which would simplify reserves administration.[2] The Board is also proposing amendments to subpart A of Regulation J to clarify where a check or other item is deemed to be accepted when it is sent to a Reserve Bank. Specifically, these amendments would clarify that when an institution sends a check or other item for collection to a Reserve Bank, the institution's Administrative Reserve Bank is deemed to have accepted deposit of the item even if the item was sent directly to another Reserve Bank.[3] In addition, the Board is proposing amendments that would clarify the application of subpart B of Regulation J. Under these amendments, subpart B of Regulation J would continue to apply to a Fedwire funds transfer even if that funds transfer also meets the definition of ''remittance transfer'' under the recently revised Electronic Fund Transfer Act (''EFTA'').

II. Overview of Proposed Amendments

Eliminate References to As-of Adjustments

Regulation J defines ''as-of adjustment'' for purposes of subpart B of the regulation as ''a debit or credit, for reserve- or clearing-balance maintenance purposes only, applied to the reserve or clearing balance of a bank that either sends a payment order to a Federal Reserve Bank, or that receives a payment order from a Federal Reserve Bank, in lieu of an interest charge or

[1] If the Board eliminates references to as-of adjustments in its Regulations D and J, the Reserve Banks would make conforming changes to their operating circulars that set forth the terms of their services. The Reserve Banks' operating circulars are available at *http://www.frbservices.org/regulations/operating_circulars.html.*

[2] The proposed amendments to Regulation D, designed to reduce the administrative and operational costs associated with reserve requirements, would discontinue as-of adjustments for deposit revisions and replace all other as-of adjustments with direct compensation. The amendments would also create a common two-week maintenance period for all depository institutions, create a penalty-free band around reserve balance requirements in place of carryover and routine waivers, and eliminate the contractual clearing balance program.

[3] An institution's Administrative Reserve Bank is the Reserve Bank in whose District the institution is located. 12 CFR 210.2(c), *see* section 204.3(g) of Regulation D, 12 CFR 204.3(g) (location of depository institutions).

payment.''[4] Under Regulation J, a Reserve Bank may use either an as-of adjustment or direct compensation (at the federal funds rate) to compensate for an error in transaction processing or other damages owed in connection with a Fedwire funds transfer. An as-of adjustment corrects the average level of balances maintained by the depository institution to the level that would have resulted had the error not been made. As-of adjustments (and direct compensation) are based on the principle that a depository institution should not gain or lose in its reserve or clearing balance position as a result of a Reserve Bank accounting or administrative error or a Reserve Bank delay in processing transactions. Regulation J also provides in subpart A that a Reserve Bank's operating circulars may include procedures for paying interest in the form of as-of adjustments in relation to the collection of checks and other items.

As noted above, the Board is proposing to amend Regulation D to simplify the rules governing the administration of reserve requirements. The proposed Regulation D amendments include discontinuing as-of adjustments related to deposit reporting revisions and replacing all other as-of adjustments with direct compensation. Direct compensation is either a debit or credit applied to an account to offset the effect of an error. Consistent with the Regulation D proposal, the Board is proposing to amend sections 210.3(a), 210.26(b), and 210.32(b) (along with the corresponding commentary) of Regulation J to eliminate references to as-of adjustments. Under the proposal, a Reserve Bank would continue to be able to pay direct compensation to a depository institution based on the federal funds rate in accordance with section 210.32(b) section 4A–506 of article 4A of the Uniform Commercial Code (UCC), as incorporated into Regulation J.[5] The Board requests comment on whether use of the federal funds rate for the calculation of direct compensation is appropriate, and if not, the rate that the Board should use.[6] The Board further requests comment on whether the Board should eliminate section 210.32(b)(1) of Regulation J entirely, as the Reserve Banks could simply pay direct compensation based on the provisions of UCC section 4A–506, which is already incorporated into Regulation J.

Acceptance of Deposits of Items

Section 210.4 of Regulation J governs the sending and handling of checks and other items sent to Reserve Banks. Section 210.4 currently specifies the identity and order of the parties that are deemed to handle an item sent to a Reserve Bank for purposes of determining the rights and liabilities of the parties under Regulation J, Regulation CC (12 CFR part 229), and the UCC.

The Reserve Banks have long permitted institutions to send checks and other items for collection directly to a Reserve Bank other than the institution's Administrative Reserve Bank. These ''direct sends'' have facilitated a more efficient and less costly check-processing infrastructure for depository institutions as well as for Reserve Banks. Approximately 99.9 percent of checks sent to the Reserve Banks for collection are sent as electronic items. In response to the continued nationwide decline in check usage and institutions' pervasive use of electronic check-clearing methods, the Reserve Banks have eliminated all but one of their paper-check-processing offices and have consolidated electronic check processing in a single location. An institution must send checks to the applicable location (depending on whether the check is deposited in paper or electronic form) even if it is not an office of the institution's Administrative Reserve Bank.

Regulation J currently sets forth the order in which Reserve Banks are deemed to have handled a check or other item, whether it is deposited electronically or in paper form. Specifically, section 210.4 provides that, for an item sent to a Reserve Bank for collection, the following parties are deemed to have handled the item in the following order: (1) The initial sender; (2) the initial sender's Administrative Reserve Bank; (3) the Reserve Bank that receives the item from the initial sender (if different from the initial sender's Administrative Reserve Bank); and (4) another Reserve Bank, if any, that receives the item from a Reserve Bank. The Board is proposing to amend section 210.4(b)(1)(ii) to clarify that the ''handling'' of an item by the initial sender's Administrative Reserve Bank includes accepting the item for deposit. Thus, for purposes of determining the rights and liabilities of parties that send and handle checks and other items sent to a Reserve Bank, the Administrative Reserve Bank is deemed to have accepted deposit of the item from the initial sender even if the sender sends the item directly to another Reserve Bank. Proposed 210.4(b)(3) would further clarify that, in addition to Regulation J, Regulation CC, and the UCC, the identity and order of the parties in section 210.4(b) also determines the relationships and the rights and liabilities of the parties for purposes of sections 13(1) and 16(13) of the Federal Reserve Act, which govern deposits to Reserve Banks.[7]

Application of Regulation J to ''Remittance Transfers''

As noted above, Fedwire funds transfers are governed by subpart B of Regulation J. A funds transfer, which is made up of a series of payment orders, may originate outside of the Fedwire system and be carried out only partly over Fedwire.[8] Subpart B of Regulation J currently ''governs a funds transfer that is sent through Fedwire * * * even though a portion of the funds transfer is governed by the Electronic Fund Transfer Act [EFTA], but the portion of such funds transfer that is governed by the [EFTA] is not governed by'' Regulation J.[9] This provision is slightly different from (and supersedes) the scope of UCC Article 4A–108, which provides that Article 4A does not apply ''to a funds transfer, any part of which is governed by the [EFTA].'' Until recently, the exclusion from Regulation J and Article 4A of transactions governed by the EFTA did not create any gaps or overlap, because the EFTA excludes from the definition of ''electronic fund transfer'' wire transfers over systems that are not designed primarily for consumer transfers.[10] The recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), however, added a new section 919 to the EFTA. The new section 919 of the EFTA creates new protections for consumers who send remittance transfers to designated recipients located in a foreign country. Section 919 defines ''remittance transfer'' to include an electronic transfer of funds requested by a U.S. consumer sender through a remittance transfer provider, whether or not the

[4] 12 CFR 210.26(b).

[5] The Board has incorporated Article 4A of the UCC, a uniform state law governing funds transfers, into Regulation J, appendix B. In the event of any inconsistency between subpart B of Regulation J and Article 4A, subpart B of Regulation J shall prevail. 12 CFR 210.25(b)(1).

[6] Article 4A–506(b) states that if the amount of interest is not determined by an agreement or rule, the applicable federal funds rate would apply.

[7] 12 U.S.C. 342 and 360.

[8] A payment order is an unconditional instruction of a sender to a receiving bank to pay, or to cause another bank to pay, a fixed or determinable amount of money to a beneficiary. A funds transfer is a series of payment orders made for the purpose of making payment to the beneficiary of the order. See UCC Article 4A–103(a)(1) and 4A–104(a) as incorporated into Regulation J, Appendix B.

[9] 12 CFR 210.25(b)(3).

[10] 15 U.S.C. 1693a(6)(B).

remittance transfer is also an electronic fund transfer as defined in the EFTA. Therefore, a Fedwire funds transfer could potentially be part of a remittance transfer under the new section 919 of the EFTA.[11]

Consequently, under Regulation J's existing scope provision (section 210.25(b)(3)), Fedwire funds transfers that meet the EFTA's definition of ''remittance transfer'' could be viewed as ''governed by'' the EFTA and therefore not governed by Regulation J. The Board believes that this result would lead to legal uncertainty with respect to the rights and liabilities of the parties to a Fedwire funds transfer that is also a ''remittance transfer.'' Specifically, the EFTA governs disclosures and other rights with respect to the consumer senders of remittance transfers, but does not address the interbank rights and obligations that are established in Regulation J. To avoid a gap in coverage for Fedwire funds transfers, the Board is proposing to amend section 210.25 of Regulation J to clarify that Regulation J continues to apply to ''remittance transfers'' as defined by the EFTA, to the extent there is not an inconsistency between Regulation J and section 919 of the EFTA (in which case section 919 would prevail). This proposed clarification would ensure that the provisions of Regulation J, and therefore Article 4A of the UCC, apply to all Fedwire funds transfers, except to the extent that section 919 of the EFTA and rules established thereunder apply. The proposal would include clarifications in the commentary to section 210.25 as well.

Effective Date

The Board proposes that the Regulation J amendments that would eliminate references to as-of adjustments be effective on the same date as the corresponding amendments to Regulation D. The Board proposes that these amendments take effect no earlier than the first quarter of 2012. The Board believes that the other proposed amendments to Regulation J would not require institutions to take any action or incur any cost. Therefore, the Board proposes that these amendments take effect 30 days after the Board adopts a final rule. The Board requests comment on whether the proposed effective dates are appropriate.

[11] See the Board's proposed amendments to Regulation E (12 CFR part 205) to implement section 919 of the EFTA. (76 FR 29902 (May 23, 2011).) The Regulation E rulemaking will be completed by the Consumer Financial Protection Bureau in accordance with the provisions of the Dodd-Frank Act, which transferred rulemaking responsibility for most of the EFTA from the Board to the Bureau.

III. Competitive Impact Analysis

As a matter of policy, the Board subjects all operational and legal changes that could have a substantial effect on payment system participants to a competitive impact analysis.[12] Pursuant to this policy, the Board assesses whether such proposed changes ''would have a direct and material adverse effect on the ability of other service providers to compete effectively with the Federal Reserve in providing similar services due to differing legal powers or constraints or because of a dominant market position of the Federal Reserve deriving from such legal differences.'' If as a result of this analysis the Board identifies an adverse effect on the ability to compete, the Board then assesses whether the associated benefits—such as improvements to payment system efficiency or integrity—can be achieved while minimizing the adverse effect on competition.

The proposed amendments that eliminate the use of as-of adjustments would require Reserve Banks to pay compensation in the form of explicit interest under UCC Article 4A–506, as is required of private-sector service providers. The proposed amendments to section 210.4, clarifying the status of the administrative Reserve Bank of a sender of a check, would not affect the competitive position of the Reserve Banks vis-à-vis private-sector service providers. The proposed amendments to section 210.25, clarifying the applicability of Regulation J to remittance transfers as defined in the Electronic Fund Transfer Act, do not rely on legal powers unique to the Federal Reserve; private-sector service providers of funds transfer service have the ability to similarly amend their rules. Therefore, the Board does not believe the proposed changes to Regulation J would have any direct and material adverse effect on the ability of other service providers to compete with the Reserve Banks.

IV. Initial Regulatory Flexibility Analysis

Congress enacted the Regulatory Flexibility Act (the ''RFA'') (5 U.S.C. 601 *et seq.*) to address concerns related to the effects of agency rules on small entities and the Board is sensitive to the impact its rules may impose on small entities. The RFA requires agencies either to provide an initial regulatory flexibility analysis with a proposed rule or to certify that the proposed rule will not have a significant economic impact on a substantial number of small entities. In accordance with section 3(a) of the RFA, the Board has reviewed the proposed regulation. In this case, the proposed rule would apply to all depository institutions. Based on current information, the Board believes that the proposed rule would not have a significant economic impact on a substantial number of small entities (5 U.S.C. 605(b)). Nonetheless, an Initial Regulatory Flexibility Analysis has been prepared in accordance with 5 U.S.C. 603 in order for the Board to solicit comment. The Board will, if necessary, conduct a final regulatory flexibility analysis after consideration of comments received during the public comment period.

[12] *See* ''The Federal Reserve in the Payments System,'' Fed. Res. Reg. Svc. ¶¶ 9–1550, 9–1558 (Apr. 2009).

1. Statement of the Need for, Objectives of, and Legal Basis for, the Proposed Rule

The proposed amendments to Regulation J would eliminate references to ''as-of adjustments'' consistent with the Board's proposed amendments to Regulation D (12 CFR part 204), which simplify reserves administration. The proposed amendments would also clarify that an institution's Administrative Reserve Bank is deemed to have accepted deposit of a check or other item even if the institution sends the item directly to another Federal Reserve Bank. The proposed amendments would further clarify that Regulation J continues to apply to a Fedwire funds transfer even if the funds transfer also meets the definition of ''remittance transfer'' under the Electronic Fund Transfer Act.

2. Small Entities Affected by the Proposed Rule

The proposed rule would affect all institutions that use Federal Reserve Bank check or wire transfer services. Pursuant to regulations issued by the Small Business Administration (the ''SBA'') (13 CFR 121.201), a ''small banking organization'' includes a depository institution with $175 million or less in total assets. Based on data reported as of March 31, 2011, the Board believes that there are approximately 10,723 small depository institutions, approximately 2,808 of which have a master account with the Federal Reserve.

3. Projected Reporting, Recordkeeping, and Other Compliance Requirements

The proposed rule would eliminate references to as-of adjustments and

replace the use of as-of adjustments with direct compensation based on the federal funds rate. As noted above, a depository institution should not be harmed by this amendment because the depository institution would continue to be compensated for a transaction error; the payment for the error would simply be in the form of direct compensation instead of an as-of adjustment. The other proposed amendments to Regulation J are clarifications and do not impose new requirements on depository institutions. The Board seeks information and comment on any costs that would arise from the application of the proposed rule.

4. Identification of Duplicative, Overlapping, or Conflicting Federal Rules

The Board does not believe that any Federal rules duplicate, overlap, or conflict with the proposed rule. The proposed amendment to subpart B is intended to conform to proposed changes to Regulation D. The Board seeks comment regarding any statutes or regulations that would duplicate, overlap, or conflict with the proposed rule.

5. Significant Alternatives to the Proposed Rule

The Board is unaware of any significant alternatives to the proposed rule that accomplish the stated objectives of the Board. The Board welcomes comment on any significant alternatives that would minimize the impact of the proposal on small entities.

V. Paperwork Reduction Act Analysis

In accordance with the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3506; 5 CFR part 1320 appendix A.1), the Board reviewed the proposed rule under the authority delegated to the Board by the Office of Management and Budget (OMB). No collections of information pursuant to the PRA are contained in the proposed rule.

Comments related to PRA review of this rulemaking should be sent to Cynthia Ayouch, Federal Reserve Board Clearance Officer, Division of Research and Statistics, Mail Stop 95–A, Board of Governors of the Federal Reserve System, Washington, DC 20551, with copies of such comments sent to the Office of Management and Budget, Paperwork Reduction Project (Regulation J), Washington, DC 20503.

List of Subjects in 12 CFR Part 210

Banks, banking.

Authority and Issuance

For the reasons set forth in the preamble, the Board proposes to amend Regulation J, 12 CFR part 210, as follows:

PART 210—COLLECTION OF CHECKS AND OTHER ITEMS BY FEDERAL RESERVE BANKS AND FUNDS TRANSFERS THROUGH FEDWIRE (REGULATION J)

1. The authority citation for part 210 continues to read as follows:

Authority: 12 U.S.C. 248(i), (j), and (o), 342, 360, 464, 4001–4010, and 5001–5018.

2. In § 210.3, revise paragraph (a) to read as follows:

§ 210.3 General provisions.

(a) *General.* Each Reserve Bank shall receive and handle items in accordance with this subpart, and shall issue operating circulars governing the details of its handling of items and other matters deemed appropriate by the Reserve Bank. The circulars may, among other things, classify cash items and noncash items, require separate sorts and letters, provide different closing times for the receipt of different classes or types of items, provide for instructions by an administrative Reserve Bank to other Reserve Banks, set forth terms of services, and establish procedures for adjustments on a Reserve Bank's books, including amounts, waiver of expenses, and payment of compensation.

* * * * *

3. Section 210.4 is revised to read as follows:

§ 210.4 Sending items to Reserve Banks.

(a) *Sending of items.* A sender, other than a Reserve Bank, may send any item to any Reserve Bank, whether or not the item is payable within the Reserve Bank's District, unless the sender's administrative Reserve Bank directs the sender to send the item to a specific Reserve Bank.

(b) *Handling of items.*

(1) The following parties, in the following order, are deemed to have handled an item that is sent to a Reserve Bank for collection:

(i) The initial sender;

(ii) The initial sender's administrative Reserve Bank (which is deemed to have accepted deposit of the item from the initial sender);

(iii) The Reserve Bank that receives the item from the initial sender (if different from the initial sender's administrative Reserve Bank); and

(iv) Another Reserve Bank, if any, that receives the item from a Reserve Bank.

(2) A Reserve Bank that is not described in paragraph (b)(1) of this section is not a person that handles an item and is not a collecting bank with respect to an item.

(3) The identity and order of the parties under paragraph (b)(1) of this section determine the relationships and the rights and liabilities of the parties under this subpart, part 229 of this chapter (Regulation CC), section 13(1) and section 16(13) of the Federal Reserve Act, and the Uniform Commercial Code. An initial sender's administrative Reserve Bank that is deemed to accept an item for deposit or handle an item is also deemed to be a sender with respect to that item. The Reserve Banks that are deemed to handle an item are deemed to be agents or subagents of the owner of the item, as provided in § 210.6(a) of this subpart.

(c) *Checks received at par.* The Reserve Banks shall receive cash items and other checks at par.

4. In § 210.25, revise paragraphs (b)(1) and (b)(3) to read as follows:

§ 210.25 Authority, purpose, and scope.

* * * * *

(b) * * *

(1) This subpart incorporates the provisions of article 4A set forth in appendix B to this subpart. In the event of an inconsistency between the provisions of the sections of this subpart and appendix B to this subpart, the provisions of the sections of this subpart shall prevail. In the event of an inconsistency between the provisions this subpart and section 919 of the Electronic Fund Transfer Act, section 919 of the Electronic Fund Transfer Act shall prevail.

* * * * *

(3) This subpart governs a funds transfer that is sent through Fedwire, as provided in paragraph (b)(2) of this section, even though a portion of the funds transfer is governed by the Electronic Fund Transfer Act, but the portion of such funds transfer that is governed by the Electronic Fund Transfer Act (other than section 919 governing remittance transfers) is not governed by this subpart.

* * * * *

§ 210.26 [Amended]

5. In § 210.26, paragraph (b) is removed and reserved.

6. In § 210.32, revise paragraphs (b)(1) and (b)(2), to read as follows:

§ 210.32 Federal Reserve Bank liability; payment of interest.

* * * * *

(b) * * *

(1) A Federal Reserve Bank shall satisfy its obligation, or that of another Federal Reserve Bank, to pay compensation in the form of interest under article 4A by paying compensation in the form of interest to its sender, its receiving bank, its beneficiary, or another party to the funds transfer that is entitled to such payment, in an amount that is calculated in accordance with section 4A–506 of article 4A.

(2) If the sender or receiving bank that is the recipient of an interest payment is not the party entitled to compensation under article 4A, the sender or receiving bank shall pass through the benefit of the interest payment by making an interest payment, as of the day the interest payment is effected, to the party entitled to compensation. The interest payment that is made to the party entitled to compensation shall not be less than the value of the interest payment that was provided by the Federal Reserve Bank to the sender or receiving bank. The party entitled to compensation may agree to accept compensation in a form other than a direct interest payment, provided that such an alternative form of compensation is not less than the value of the interest payment that otherwise would be made.

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7. In appendix A to subpart B:

a. In section 210.25, revise paragraph (b).

b. In section 210.26, revise paragraph (i).

c. In section 210.32, revise paragraph (b).

The revisions read as follows:

Appendix A to Subpart B of Part 210—Commentary

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Section 210.25—Authority, Purpose, and Scope

* * * * *

(b) *Scope.* (1) Subpart B of this part incorporates the provisions of article 4A set forth in appendix B of this part. The provisions set forth expressly in the sections of subpart B of this part supersede or preempt any inconsistent provisions of article 4A as set forth in appendix B of this part or as enacted in any state. The official comments to article 4A are not incorporated in subpart B of this part or this commentary to subpart B of this part, but the official comments may be useful in interpreting article 4A. Because section 4A–105 refers to other provisions of the Uniform Commercial Code, *e.g.,* definitions in article 1 of the UCC, these other provisions of the UCC, as approved by the National Conference of Commissioners on Uniform State Laws and the American Law Institute, from time to time, are also incorporated in subpart B of this part. Subpart B of this part applies to any party to a Fedwire funds transfer that is in privity with a Federal Reserve Bank. These parties include a sender (bank or nonbank) that sends a payment order directly to a Federal Reserve Bank, a receiving bank that receives a payment order directly from a Federal Reserve Bank, and a beneficiary that receives credit to an account that it uses or maintains at a Federal Reserve Bank for a payment order sent to a Federal Reserve Bank. Other parties to a funds transfer are covered by this subpart to the same extent that this subpart would apply to them if this subpart were a ''funds-transfer system rule'' under article 4A that selected subpart B of this part as the governing law.

(2) The scope of the applicability of a funds-transfer system rule under article 4A is specified in section 4A–501(b), and the scope of the choice of law provision is specified in section 4A–507(c). Under section 4A–507(c), a choice of law provision is binding on the participants in a funds-transfer system and certain other parties having notice that the funds-transfer system might be used for the funds transfer and of the choice of law provision. The Uniform Commercial Code provides that a person has notice when the person has actual knowledge, receives notification, or has reason to know from all the facts and circumstances known to the person at the time in question. (See UCC § 1–201(25).) However, under sections 4A–507(b) and 4A–507(d), a choice of law by agreement of the parties takes precedence over a choice of law made by funds-transfer system rule.

(3) If originators, receiving banks, and beneficiaries that are not in privity with a Federal Reserve Bank have the notice contemplated by Section 4A–507(c) or if those parties agree to be bound by subpart B of this part, subpart B of this part generally would apply to payment orders between those remote parties, including participants in other funds-transfer systems. For example, a funds transfer may be sent from an originator's bank through a funds-transfer system other than Fedwire to a receiving bank which, in turn, sends a payment order through Fedwire to execute the funds transfer. Similarly, a Federal Reserve Bank may execute a payment order through Fedwire to a receiving bank that sends it through a funds-transfer system other than Fedwire to a beneficiary's bank. In the first example, if the originator's bank has notice that Fedwire may be used to effect part of the funds transfer, the sending of the payment order through the other funds-transfer system to the receiving bank will be governed by subpart B of this part unless the parties to the payment order have agreed otherwise. In the second example, if the beneficiary's bank has notice that Fedwire may be used to effect part of the funds transfer, the sending of the payment order to the beneficiary's bank through the other funds-transfer system will be governed by subpart B of this part unless the parties have agreed otherwise. In both cases, the other funds-transfer system's rules would also apply to, at a minimum, the portion of these funds transfers going through that funds transfer system. Because subpart B of this part is federal law, to the extent of any inconsistency, subpart B of this part will take precedence over any funds-transfer system rule applicable to the remote sender or receiving bank or to a Federal Reserve Bank. If remote parties to a funds transfer, a portion of which is sent through Fedwire, have expressly selected by agreement a law other than subpart B of this part under section 4A–507(b), subpart B of this part would not take precedence over the choice of law made by the agreement even though the remote parties had notice that Fedwire may be used and of the governing law. (See 4A–507(d).) In addition, subpart B of this part would not apply to a funds transfer sent through another funds-transfer system where no Federal Reserve Bank handles the funds transfer, even though settlement for the funds transfer is made by means of a separate net settlement or funds transfer through Fedwire.

(4) Under section 4A–108, article 4A does not apply to a funds transfer, any part of which is governed by the Electronic Fund Transfer Act (EFTA) (15 U.S.C. 1693 *et seq.*). In general, Fedwire funds transfers to or from consumer accounts are exempt from the EFTA and Regulation E (12 CFR part 205). A funds transfer from a consumer originator or a funds transfer to a consumer beneficiary could be carried out in part through Fedwire and in part through an automated clearinghouse or other means that is subject to the EFTA or Regulation E. In these cases, subpart B would not govern the portion of the funds transfer that is governed by the EFTA or Regulation E. (See the commentary to section 210.26(i), ''Payment Order''.)

(5) Section 919 of the EFTA, however, governs ''remittance transfers,'' which may include Fedwire funds transfers. Section 919 of the EFTA sets out the obligations of remittance transfer providers with respect to consumer senders of remittance transfers. Section 919 of the EFTA generally does not affect the rights and obligations of financial institutions involved in a remittance transfer. To the extent that a Fedwire funds transfer is a ''remittance transfer'' governed by section 919 of the EFTA, it continues to be governed by subpart B, except that, in the event of an inconsistency between the provisions of subpart B and section 919 of the EFTA, section 919 of the EFTA shall prevail. For example, a consumer may initiate a remittance transfer governed by EFTA section 919 from the consumer's account at a depository institution, and the depository institution may initiate that transfer by sending a payment order to a Reserve Bank through the Fedwire funds system. If the consumer subsequently exercised the right to cancel the remittance transfer and obtain a refund under the terms of EFTA section 919, the depository institution would be required to comply with section 919 even if the institution does not have a right to reverse the payment order sent to the Reserve Bank under subpart B.

(6) Finally, section 4A–404(a) provides that a beneficiary's bank is obliged to pay the amount of a payment order to the beneficiary on the payment date unless acceptance of the payment order occurs on the payment date after the close of the funds-transfer business day of the bank. The Expedited Funds Availability Act provides that funds received by a bank by wire transfer shall be available

for withdrawal not later than the banking day after the business day on which such funds are received (12 U.S.C. 4002(a)). That act also preempts any provision of state law that was not effective on September 1, 1989, that is inconsistent with that act or its implementing Regulation CC (12 CFR 229). Accordingly, the Expedited Funds Availability Act and Regulation CC may preempt section 4A–404(a) as enacted in any state. In order to ensure that section 4A–404(a), or other provisions of article 4A, as incorporated in subpart B of this part, do not take precedence over provisions of the Expedited Funds Availability Act, this section provides that where subpart B of this part establishes rights or obligations that are also governed by the Expedited Funds Availability Act or Regulation CC, the Expedited Funds Availability Act or Regulation CC provision shall apply and subpart B of this part shall not apply.

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Section 210.26—Definitions

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(i) *Payment Order.* (1) The definition of ''payment order'' in subpart B of this part differs from the section 4A–103(a)(1) definition. The subpart B definition clarifies that, for the purposes of Subpart B of this part, automated clearinghouse transfers and certain messages that are transmitted through Fedwire are not payment orders. Federal Reserve Banks and banks participating in Fedwire send various types of messages relating to payment orders or to other matters, through Fedwire, that are not intended to be payment orders. Under the subpart B definition, these messages, and messages involved with automated clearinghouse transfers, are not ''payment orders'' and therefore are not governed by this subpart. The operating circulars of the Federal Reserve Banks specify those messages that may be transmitted through Fedwire but that are not payment orders.

(2) In some cases, messages sent through Fedwire, such as certain requests for credit transfer, may be payment orders under article 4A, but are not treated as payment orders under subpart B because they are not an instruction to a Federal Reserve Bank to pay money.

(3) This subpart and article 4A govern a payment order even though the originator's or beneficiary's account may be a consumer account established primarily for personal, family, or household purposes. Under section 4A–108, article 4A does not apply to a funds transfer any part of which is governed by the Electronic Fund Transfer Act. That act, and Regulation E implementing it, do not apply to funds transfers through Fedwire (see 15 U.S.C. 1693a(6)(B) and 12 CFR 205.3(b)), except that section 919 of the Electronic Fund Transfer Act may govern a Fedwire funds transfer that is a ''remittance transfer.'' Such remittance transfers that are Fedwire funds transfers continue to be governed by this subpart. Thus, this subpart applies to all funds transfers through Fedwire even though some such transfers involve originators or beneficiaries that are consumers. (See also section 210.25(b) and accompanying commentary.)

* * * * *

Section 210.32—Federal Reserve Bank Liability; Payment of Interest

* * * * *

(b) *Payment of interest.* (1) Under article 4A, a Federal Reserve Bank may be required to pay compensation in the form of interest to another party in connection with its handling of a funds transfer. For example, payment of compensation in the form of interest is required in certain situations pursuant to sections 4A–204 (relating to refund of payment and duty of customer to report with respect to unauthorized payment order), 4A–209 (relating to acceptance of payment order), 4A–210 (relating to rejection of payment order), 4A–304 (relating to duty of sender to report erroneously executed payment order), 4A–305 (relating to liability for late or improper execution or failure to execute a payment order), 4A–402 (relating to obligation of sender to pay receiving bank), and 4A–404 (relating to obligation of beneficiary's bank to pay and give notice to beneficiary). Under section 4A–506(a), the amount of such interest may be determined by agreement between the sender and receiving bank or by funds-transfer system rule. If there is no such agreement, under section 4A–506(b), the amount of interest is based on the federal funds rate. Section 210.32(b) requires Federal Reserve Banks to provide compensation through an explicit interest payment.

(2) Interest would be calculated in accordance with the procedures specified in section 4A–506(b). Similarly, compensation in the form of explicit interest will be paid to government senders, receiving banks, or beneficiaries described in section 210.25(d) if they are entitled to interest under this subpart. A Federal Reserve Bank may also, in its discretion, pay explicit interest directly to a remote party to a Fedwire funds transfer that is entitled to interest, rather than providing compensation to its direct sender or receiving bank.

(3) If a bank that received an explicit interest payment is not the party entitled to interest compensation under article 4A, the bank must pass the benefit of the explicit interest payment made to it to the party that is entitled to compensation in the form of interest from a Federal Reserve Bank. The benefit may be passed on either in the form of a direct payment of interest or in the form of a compensating balance, if the party entitled to interest agrees to accept the other form of compensation, and the value of the compensating balance is at least equivalent to the value of the explicit interest that otherwise would have been provided.

By order of the Board of Governors of the Federal Reserve System, October 7, 2011.

Jennifer J. Johnson,

Secretary of the Board.

[FR Doc. 2011–26811 Filed 10–17–11; 8:45 am]

BILLING CODE 6210–01–P

FINANCIAL STABILITY OVERSIGHT COUNCIL

12 CFR Part 1310

RIN 4030–AA00

Authority to Require Supervision and Regulation of Certain Nonbank Financial Companies

AGENCY: Financial Stability Oversight Council.

ACTION: Second notice of proposed rulemaking and proposed interpretive guidance.

SUMMARY: Section 113 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the ''Dodd-Frank Act'') authorizes the Financial Stability Oversight Council (the ''Council'') to require a nonbank financial company to be supervised by the Board of Governors of the Federal Reserve System (the ''Board of Governors'') and be subject to prudential standards in accordance with Title I of the Dodd-Frank Act if the Council determines that material financial distress at the nonbank financial company, or the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States.

The proposed rule and attached guidance describe the manner in which the Council intends to apply the statutory standards and considerations, and the processes and procedures that the Council intends to follow, in making determinations under section 113 of the Dodd-Frank Act. The Council issued an advance notice of proposed rulemaking on October 6, 2010, and a notice of proposed rulemaking on January 26, 2011, regarding determinations under section 113.

DATES: *Comment due date:* December 19, 2011.

ADDRESSES: Interested persons are invited to submit comments regarding this notice of proposed rulemaking according to the instructions below. All submissions must refer to the document title. The Council encourages the early submission of comments.

Electronic Submission of Comments: Interested persons may submit comments electronically through the Federal eRulemaking Portal at *http://www.regulations.gov.* Electronic submission of comments allows the commenter maximum time to prepare and submit a comment, ensures timely receipt, and enables the Council to make them available to the public. Comments submitted electronically through the

http://www.regulations.gov website can be viewed by other commenters and interested members of the public. Commenters should follow the instructions provided on that site to submit comments electronically.

Mail: Send comments to Financial Stability Oversight Council, Attn: Lance Auer, 1500 Pennsylvania Avenue, NW., Washington, DC 20220.

Note: To receive consideration as public comments, comments must be submitted through the method specified.

Public Inspection of Public Comments: All properly submitted comments will be available for inspection and downloading at *http://www.regulations.gov.*

Additional Instructions: In general comments received, including attachments and other supporting materials, are part of the public record and are available to the public. Do not submit any information in your comment or supporting materials that you consider confidential or inappropriate for public disclosure.

FOR FURTHER INFORMATION CONTACT: Lance Auer, Office of Domestic Finance, Treasury, at (202) 622–1262, or Eric Froman, Office of the General Counsel, Treasury, at (202) 622–1942. All responses to this notice should be submitted via *http://www.regulations.gov* to ensure consideration.

SUPPLEMENTARY INFORMATION:

I. Background

Section 111 of the Dodd-Frank Act (12 U.S.C. 5321) established the Financial Stability Oversight Council. Among the purposes of the Council under section 112 of the Dodd-Frank Act (12 U.S.C. 5322) are ''(A) to identify risks to the financial stability of the United States that could arise from the material financial distress or failure, or ongoing activities, of large, interconnected bank holding companies or nonbank financial companies, or that could arise outside the financial services marketplace; (B) to promote market discipline, by eliminating expectations on the part of shareholders, creditors, and counterparties of such companies that the Government will shield them from losses in the event of failure; and (C) to respond to emerging threats to the stability of the United States financial system.''

In the recent financial crisis, financial distress at certain nonbank financial companies contributed to a broad seizing up of financial markets, stress at other financial firms, and a deep global recession with a considerable drop in employment, the classic symptoms of financial instability. These nonbank financial companies were not subject to the type of regulation and consolidated supervision applied to bank holding companies, nor were there effective mechanisms in place to resolve the largest and most interconnected of these nonbank financial companies without causing further instability. To address any potential risks posed to U.S. financial stability by these companies, the Dodd-Frank Act authorizes the Council to determine that certain nonbank financial companies will be subject to supervision by the Board of Governors and prudential standards. Title I of the Dodd-Frank Act defines a ''nonbank financial company'' as a domestic or foreign company that is ''predominantly engaged in financial activities'' in the United States, other than bank holding companies and certain other types of firms.[1] The Council intends to interpret the term ''company'' broadly with respect to nonbank financial companies and other companies in connection with section 113 of the Dodd-Frank Act, to include any corporation, limited liability company, partnership, business trust, association (incorporated or unincorporated), or similar organization. The Dodd-Frank Act provides that a company is ''predominantly engaged'' in financial activities if either (i) the annual gross revenues derived by the company and all of its subsidiaries from financial activities, as well as from the ownership or control of insured depository institutions, represent 85 percent or more of the consolidated annual gross revenues of the company; or (ii) the consolidated assets of the company and all of its subsidiaries related to financial activities, as well as related to the ownership or control of insured depository institutions, represent 85 percent or more of the consolidated assets of the company. The Dodd-Frank Act requires the Board of Governors to establish the requirements for determining whether a company is ''predominantly engaged in financial activities'' for this purpose.[2]

The Council issued an advance notice of proposed rulemaking (the ''ANPR'') on October 6, 2010 (75 FR 61653), in which it requested public comment on the statutory factors that the Dodd-Frank Act requires the Council to consider in determining whether a nonbank financial company should be supervised by the Board of Governors and subject to prudential standards. The ANPR posed 15 questions, all of which addressed the application of the statutory considerations that the Council must take into account in the process of determining whether a nonbank financial company should be subject to supervision by the Board of Governors and be subject to prudential standards (the ''Determination Process'').

On January 26, 2011, the Council issued a notice of proposed rulemaking (the ''NPR'') (76 FR 4555) through which it sought public comment regarding the specific criteria and analytic framework that the Council intends to apply in the Determination Process. The comment period for the NPR closed on February 25, 2011.

In response to comments that the Council received on the NPR, the Council is issuing a second notice of proposed rulemaking (the ''Proposed Rule'') and proposed interpretive guidance (the ''Proposed Guidance'') to provide (i) additional details regarding the framework that the Council intends to use in the process of assessing whether a nonbank financial company could pose a threat to U.S. financial stability, and (ii) further opportunity for public comment on the Council's proposed approach to the Determination Process.

II. Overview of Comments

The Council received 35 comments in response to the NPR, of which 11 were from trade associations or advocacy groups, 10 were from the insurance industry, eight were from entities in the asset management industry, two were from law firms, two were from individuals, one was from a think tank, and one was from a specialty finance company. (Comment letters are available online at: *http://www.regulations.gov.*) In addition to issuing the ANPR and the NPR for public comment, staff of Council member agencies met with financial industry representatives to discuss the proposals. Meeting participants generally reiterated the views expressed in their comment submissions. Many commenters responding to the NPR referred to comments that they previously had submitted in response to the ANPR. While this preamble describes many of the comments submitted in response to the ANPR and

[1] *See* 12 U.S.C. 5311(a)(4).

[2] *See* 12 U.S.C. 5311(b). The Board of Governors has requested comment on a proposed rule that would establish these requirements. *See* 76 FR 7731 (February 11, 2011). The Board of Governors' proposed rule would establish a process by which a company may request a determination by the Board of Governors as to whether a particular activity is financial in nature. In addition, the proposed rule would provide the Board of Governors the authority to determine that a company is predominantly engaged in financial activities based on all the facts and circumstances.

the NPR, and describes how the Proposed Rule and Proposed Guidance address certain of those comments, the Council expects to provide a more complete discussion of the comments submitted in response to the Proposed Rule and Proposed Guidance after considering the comments received during the comment period on the Proposed Rule and Proposed Guidance.

The comments addressed various aspects of the NPR, but the majority of comments addressed one or more of the following three broad issues: the substantive content of the NPR, the scope of the Council's Constitutional or statutory authority, and the Council's compliance with the Administrative Procedure Act (the ''APA'').

A. Substantive Content of the NPR

The majority of commenters asserted that the NPR lacked the necessary level of specificity and detail needed to provide meaningful guidance regarding the manner in which the Council intends to exercise its determination authority under section 113 of the Dodd-Frank Act.[3]

Some commenters asserted that the Council should include the proposed six-category framework in the rule text, rather than in the preamble, so as to require the Council to apply the framework in the Determination Process. The majority of commenters requested that the Council issue specific metrics to measure the six categories, and any relative weighting that the Council may assign to one or more of the six categories, for public comment. Other commenters suggested that the Council define the terms ''financial stability'' and ''material financial distress'' before establishing any specific metrics, as the Council should consider such definitions when identifying appropriate metrics.

[3] Many commenters stated that the NPR did not adequately define each of the 10 statutory considerations that the Council must consider when determining whether a nonbank financial company could pose a threat to the financial stability of the United States. Some commenters asserted that they were unable to provide substantive input regarding the determination framework set forth in the NPR, because the Council failed to explain its rationale for selecting the six framework categories. Other commenters stated that the Council's NPR failed to provide nonbank financial companies any basis on which to make informed business decisions in anticipation of a potential determination, such as decisions related to potential expansion into new lines of business, mergers, acquisitions, financial investments, and hiring plans, as companies may delay or avoid business pursuits in light of the uncertainty surrounding the Determination Process. Other commenters stated that the lack of clarity in the NPR failed to provide nonbank financial companies with a basis on which to consider actions that could reduce the company's potential to pose a threat to U.S. financial stability, and thereby lessen the need for determination.

Many commenters asserted that the Council provided an insufficient level of detail regarding the Determination Process. Specifically, commenters suggested that the initial notice of consideration should provide a detailed explanation of the basis of the Council's consideration of the nonbank financial company for a proposed determination, including an outline of the specific statutory considerations on which the Council based its decision.

Some commenters, the majority of whom represented the insurance industry, noted that two insurance-related positions on the Council were vacant: (1) An independent insurance expert (to be appointed by the President) and (2) the Director of the Federal Insurance Office (to be appointed by the Secretary of the Treasury). These commenters requested that the Council delay issuing a final rule until those Council positions are filled.[4]

Comments on the Six-Factor Framework

A majority of commenters addressed various aspects of the proposed six-category framework that the Council set forth in the NPR. Several commenters praised the six framework categories as useful tools to assess a nonbank financial company's potential to pose a threat to U.S. financial stability. One commenter expressed concern that the Council intended to use the six-category framework as a proxy for the 10 specific statutory considerations that the Council is required to consider when determining whether a nonbank financial company could pose a threat to U.S. financial stability.

Commenters also asked for clarification regarding the manner in which the Council intends to assess a nonbank financial company within each category and provided suggestions regarding the manner in which the Council should do so. Some of these comments are described below.

Interconnectedness

Many commenters expressed the view that interconnectedness with the broader financial system is the most important indicator of a nonbank financial company's potential to pose a threat to U.S. financial stability. Some commenters suggested that the Council should assess whether failure of a nonbank financial company would threaten the financial condition and competitive position of other significant financial companies when evaluating a nonbank financial company under this category. Commenters from the asset management industry and the insurance industry provided comments on how interconnectedness should be measured within those industries.

[4] S. Roy Woodall has been appointed by President Obama as the independent insurance expert on the Council. Michael McRaith has been appointed as the Director of the Federal Insurance Office.

Substitutability

Many commenters stated that the substitutability of a nonbank financial company's goods or services that are important to the overall financial system is an important factor that the Council should consider in the Determination Process. Commenters from the asset management and insurance industries noted that there is little concentration in the asset management and insurance industries.

Size

Commenters generally noted that size is an important factor that the Council should consider in the Determination Process, but that size alone should not provide a sufficient basis on which to make a determination with respect to a nonbank financial company, absent other considerations, such as the nonbank financial company's interconnectedness or contagion risk. Many commenters expressed concern that the Council had not sufficiently disclosed how it would measure size across different industries.

Leverage

Some commenters asserted that leverage is an important factor that the Council should consider in the Determination Process, while others suggested that different considerations, such as reliance on debt financing, would provide a more meaningful assessment of the potential of a nonbank financial company to pose a threat to U.S. financial stability. In addition, commenters asked that the Council clarify the manner in which it intends to calculate a nonbank financial company's leverage.

Liquidity Risk and Maturity Mismatch

Commenters generally agreed that liquidity risk and maturity mismatch are important criteria for assessing the likelihood that material financial distress at a nonbank financial company could pose a threat to U.S. financial stability, but certain commenters asked the Council to clarify the manner in which it intends to measure this category. Commenters from the asset management industry expressed the view that firms within the asset management industry are not vulnerable to significant liquidity risk or maturity mismatches. Commenters from the insurance industry noted that the

insurance industry has had very little liquidity risk traditionally.

Existing Regulatory Scrutiny

Many commenters stated that an assessment of existing regulatory scrutiny is an important consideration for purposes of determining whether a nonbank financial company could pose a threat to U.S. financial stability. Some commenters suggested that the Council consider not only the degree to which regulatory requirements are already applicable to a particular nonbank financial company, but also any new regulatory requirements to which the nonbank financial company will become subject pursuant to new requirements imposed by the Dodd-Frank Act.

B. The Council's Authority

Some commenters asserted that the Council does not have the authority to issue rules and regulations setting forth the process and standards it will follow in fulfilling the Council's statutory functions related to nonbank financial company determinations under section 113 of the Dodd-Frank Act. In particular, commenters noted that while the Dodd-Frank Act authorizes the Council to issue such rules as may be necessary for the conduct of the business of the Council, the Dodd-Frank Act does not specifically authorize the Council to issue rules or regulations regarding matters related to determinations regarding nonbank financial companies.

C. Compliance With the APA

Commenters stated that the rule is too vague to satisfy the ''notice and comment'' requirements under the APA, the requirement in Presidential Executive Order 13563, ''Improving Regulation and Regulatory Review'' [5] that the rule contain clear, specific regulatory criteria and a cost/benefit analysis, or the due process requirements of the United States Constitution.

III. Overview of the Proposed Rule and the Proposed Guidance

In developing the Proposed Rule, the Council has carefully considered the comments received on the ANPR and the NPR, as well as the language and legislative history of the Dodd-Frank Act. After this review, the Council has determined to propose a rule that has been modified to provide additional details about the processes and procedures through which the Council may make a determination under section 113 of the Dodd-Frank Act, and the manner in which a nonbank financial company may respond to and contest a proposed determination.

In addition, the Council is issuing, with a request for comment, as an appendix to the Proposed Rule, the Proposed Guidance. Among other aspects of the Proposed Guidance, the Council invites interested parties to comment on—

- Key terms and concepts related to the Council's determination authority, including ''material financial distress'' and ''threat to financial stability'';
- The six-category framework that the Council intends to use to determine whether a nonbank financial company could pose a threat to the financial stability of the United States, including examples of quantitative metrics for assessing each category;
- The six uniform quantitative thresholds that the Council intends to use to identify those nonbank financial companies that will be subject to further evaluation by the Council; and
- The process that the Council intends to follow when considering whether to subject a nonbank financial company to supervision by the Board of Governors and prudential standards.

The Council's ultimate determination will be based on an evaluation of each of the statutory considerations taking into account facts and circumstances relevant to each nonbank financial company.

The Proposed Rule and Proposed Guidance, as well as the Council's responses to the comments received, are discussed in greater detail below.

As noted above under ''Overview of Comments,'' the Council received comments that addressed virtually all aspects of the Council's authority to make a determination with respect to nonbank financial companies under section 113 of the Dodd-Frank Act. The Council is committed to fostering transparency with respect to the Determination Process, and the Proposed Rule and Proposed Guidance are intended to address such concerns by providing a detailed description of: (i) The profile of those nonbank financial companies that the Council likely will evaluate for potential determination so as to minimize the uncertainty to which many commenters referred regarding the Determination Process, and (ii) the metrics that the Council intends to use when analyzing companies at various stages of the Determination Process, including examples of the metrics that the Council intends to use when evaluating a nonbank financial company using the six-category framework.

The Council has numerous authorities and tools to carry out its statutory duty to monitor the financial stability of the United States. In addition to the Council's determination authority under section 113 of the Dodd-Frank Act, the Council has the authority to make recommendations to primary financial regulatory agencies to apply new or heightened standards and safeguards for a financial activity or practice conducted by bank holding companies or nonbank financial companies under the jurisdiction of such agencies if the Council determines that the conduct, scope, nature, size, scale, concentration, or interconnectedness of such activity or practice could create or increase the risk of significant liquidity, credit, or other problems spreading among bank holding companies and nonbank financial companies, U.S. financial markets, or low-income, minority, or underserved communities.[6] In addition, the Council may designate financial market utilities and payment, clearing and settlement activities that the Council determines are, or are likely to become, systemically important.[7] The Council expects that its response to any potential threat to financial stability will be based on an assessment of the circumstances.

Pursuant to section 115(a) of the Dodd-Frank Act, the Council may also make recommendations to the Board of Governors concerning the establishment and refinement of prudential standards and reporting and disclosure standards applicable to nonbank financial companies supervised by the Board of Governors pursuant to section 113 of the Dodd-Frank Act. In making such recommendations, the Dodd-Frank Act also authorizes the Council to differentiate among companies on an individual basis or by category, taking into consideration their capital structure, riskiness, complexity, financial activities (including the financial activities of their subsidiaries), size, and any other risk-related factors that the Council deems appropriate. In addition, section 165 of the Dodd-Frank Act gives the Board of Governors the ability to tailor the application of the prudential standards on its own.

Commenters are encouraged to provide comment on the Proposed Rule and Proposed Guidance. The Council will consider comments received on the Proposed Rule and Proposed Guidance as the Council continues to develop the

[5] Available at *http://www.gpo.gov/fdsys/pkg/FR-2011-01-21/pdf/2011-1385.pdf.*

[6] *See* 12 U.S.C. 5330(a).

[7] *See* 12 U.S.C. 5463(a)(1).

approach that the Council intends to take in the Determination Process.

A. Statutory Considerations for Determinations

Section 113 of the Dodd-Frank Act authorizes the Council to subject a nonbank financial company to supervision by the Board of Governors and prudential standards if the Council determines that (i) material financial distress at the nonbank financial company could pose a threat to the financial stability of the United States (the ''First Determination Standard''), or (ii) the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company could pose a threat to the financial stability of the United States (the ''Second Determination Standard'').

Pursuant to the provisions of the Dodd-Frank Act, the Council is required to consider the following statutory considerations when evaluating whether to make this determination with respect to a nonbank financial company: [8]

(A) The extent of the leverage of the company;

(B) The extent and nature of the off–balance-sheet exposures of the company;

(C) The extent and nature of the transactions and relationships of the company with other significant nonbank financial companies and significant bank holding companies;

(D) The importance of the company as a source of credit for households, businesses, and State and local governments and as a source of liquidity for the U.S. financial system;

(E) The importance of the company as a source of credit for low-income, minority, or underserved communities, and the impact that the failure of such company would have on the availability of credit in such communities;

(F) The extent to which assets are managed rather than owned by the company, and the extent to which ownership of assets under management is diffuse;

(G) The nature, scope, size, scale, concentration, interconnectedness, and mix of the activities of the company;

(H) The degree to which the company is already regulated by one or more primary financial regulatory agencies;

(I) The amount and nature of the financial assets of the company;

(J) The amount and types of the liabilities of the company, including the degree of reliance on short-term funding; and

(K) Any other risk-related factors that the Council deems appropriate.

The Council intends to take into account each of the 10 statutory considerations when determining whether one of the statutory standards for determination has been met. The Council included each of the statutory considerations in the rule text in the NPR and has retained this rule text in the Proposed Rule. The Council has provided additional detail in the Proposed Guidance regarding the manner in which the Council intends to assess nonbank financial companies under the First and Second Determination Standards. The Council has set forth proposed definitions of the terms ''material financial distress,'' which is relevant to the First Determination Standard, and ''threat to U.S. financial stability,'' which is relevant to both determination standards. The Proposed Guidance also describes the channels the Council believes are most likely to facilitate the transmission of the negative effects of a nonbank financial company's material financial distress or activities to other firms and markets, thereby posing a threat to U.S. financial stability.

In exercising its anti-evasion authority with respect to a U.S. nonbank financial company or foreign nonbank financial company, the Council must consider the relevant statutory factors applicable to a U.S. or foreign nonbank financial company, respectively. The Proposed Rule retains the process for making anti-evasion determinations that was set forth in the NPR. The Council may make such a determination either on its own initiative or at the request of the Board of Governors.

B. Process for Identifying Nonbank Financial Companies for Further Evaluation

In response to comments requesting more detail regarding the Determination Process, the Proposed Guidance provides a detailed description of the manner in which the Council intends to conduct the Determination Process. For example, the Proposed Guidance provides a description of the manner in which the Council intends to identify nonbank financial companies for further evaluation. The Council intends to evaluate a broad group of nonbank financial companies by applying uniform quantitative thresholds representing the framework categories that are more readily quantified, namely size, interconnectedness, leverage, and liquidity risk and maturity mismatch. A nonbank financial company would be subject to additional review if it meets both the size threshold and any one of the other quantitative thresholds. The Council believes that this set of thresholds will help a nonbank financial company predict whether such company will likely be subject to additional review by the Council.

In addition to a discussion of the analytic framework, the Proposed Guidance describes the manner in which the Council intends to analyze the companies included in each subsequent stage in the Determination Process to determine whether any nonbank financial company initially identified could pose a threat to U.S. financial stability.

The Council expects that the detailed description of the Determination Process contained in the Proposed Guidance, including the discussion of the analytic framework, will mitigate many of the potential negative effects that could result from the perceived uncertainty regarding the Determination Process. However, as discussed in the Proposed Guidance, the Council does not believe that a determination decision can be reduced to a formula. Each determination will be made on a firm-specific basis, taking into account qualitative, as well as quantitative, information that the Council deems relevant to a particular nonbank financial company.

C. Analytic Framework for Determinations

As set forth in the NPR, the Council proposes to use a six-category framework that is designed to incorporate each of the 10 statutory considerations for evaluating whether a nonbank financial company meets one of the two Determination Standards. The Council has incorporated the statutory considerations into the following six factors: (1) Size, (2) interconnectedness, (3) substitutability, (4) leverage, (5) liquidity risk and maturity mismatch, and (6) existing regulatory scrutiny. Three of the six categories seek to assess the potential impact of a nonbank financial company's financial distress on the broader economy: size, substitutability and interconnectedness. The remaining three categories seek to assess the vulnerability of a nonbank financial company to financial distress: leverage, liquidity risk and maturity mismatch, and existing regulatory scrutiny of the nonbank financial company. The NPR contained a table that illustrated the relationship between the 10 statutory considerations and the six framework categories. The table is also included in the Proposed Guidance. In response to

[8] This list reflects the statutory considerations applicable to a determination with respect to a U.S. nonbank financial company. The Council is required to consider similar factors in making a determination with respect to a foreign nonbank financial company.

requests by commenters, the Proposed Guidance provides further detail regarding the Council's rationale for selecting the six framework categories and provides additional clarity regarding the manner in which the six-category analytic framework incorporates each of the statutory considerations. As requested by commenters, the Proposed Guidance also sets forth examples of metrics that the Council intends to use when evaluating a nonbank financial company in each of the six categories. These metrics include several metrics proposed by commenters.

D. Additional Detail Regarding the Determination Process

In response to the public comments requesting more transparency and clarity regarding the criteria that will inform the Determination Process, the Council has developed a three-stage process the Council expects to apply for determinations in non-emergency situations. Each stage of the Determination Process would involve an analysis based on an increasing amount of information to determine whether a nonbank financial company meets either Determination Standard. The Proposed Guidance provides a detailed discussion of the proposed three-stage review process.

The first stage of the process (''Stage 1'') is designed to narrow the universe of nonbank financial companies to a smaller set of nonbank financial companies using quantitative thresholds that are broadly applicable across the financial sector. Stage 1 is not intended to indicate a determination by the Council that the nonbank financial companies identified during Stage 1 meet one of the Determination Standards. Rather, Stage 1 is intended to identify those nonbank financial companies that should be subject to further evaluation in subsequent stages of review. In the second stage of the process (''Stage 2''), the Council will conduct a comprehensive analysis of the potential for the identified nonbank financial companies to pose a threat to U.S. financial stability. In general, this analysis will be based on a broad range of quantitative and qualitative information available to the Council through existing public and regulatory sources, including industry- and firm-specific metrics beyond those analyzed in Stage 1, and information obtained from the company voluntarily.

Based on the analysis conducted during Stage 2, the Council intends to contact those nonbank financial companies that the Council believes merit further review in the third stage (''Stage 3''). Stage 3 will build on the Stage 2 analysis using quantitative and qualitative information collected directly from the nonbank financial company by the Office of Financial Research (the ''OFR'') or the appropriate regulatory agency in addition to the otherwise available information considered during Stages 1 and 2. The Council will determine whether to subject a nonbank financial company to Board of Governors supervision and prudential standards based on the results of the analyses conducted during each stage of review.

The Council considered several alternative quantitative approaches in developing a method to identify a subset of companies for additional review during Stage 1 and concluded that the thresholds-based approach set forth in the Proposed Guidance is the most appropriate method to identify this subset. In the Council's view, the thresholds-based approach provides the maximum possible transparency to the market, thereby reducing the likelihood that uncertainty about the Determination Process could negatively affect financial markets. Furthermore, the Council selected the particular Stage 1 quantitative thresholds due to their applicability to nonbank financial companies that operate in different types of financial markets and industries, and because the data underlying these thresholds are generally available from existing public and regulatory sources. Thus, nonbank financial companies should be able to reproduce the Council's initial assessments of nonbank financial companies.

The Council recognizes that the quantitative thresholds it has identified for application during Stage 1 may not provide an appropriate means to identify a subset of nonbank financial companies for further review in all cases across all financial industries and firms. While the Council will apply the Stage 1 thresholds to all types of nonbank financial companies, including financial guarantors, asset management companies, private equity firms, and hedge funds, these companies may pose risks that are not well-measured by the quantitative thresholds approach.

With respect to hedge funds and private equity firms in particular, the Council intends to apply the Stage 1 thresholds, but recognizes that less data is generally available about these companies than about certain other types of nonbank financial companies. Beginning in 2012, advisers to hedge funds and private equity firms and commodity pool operators and commodity trading advisors will be required to file Form PF with the Securities and Exchange Commission or the Commodity Futures Trading Commission, as applicable, on which form such companies will make certain financial disclosures. Using these and other data, the Council will consider whether to establish an additional set of metrics or thresholds tailored to evaluate hedge funds and private equity firms and their advisers.

In addition, the Council, its member agencies, and the OFR will analyze the extent to which there are potential threats to U.S. financial stability arising from asset management companies. This analysis will consider what threats exist, if any, and whether such threats can be mitigated by subjecting such companies to Board of Governors supervision and prudential standards, or whether they are better addressed through other regulatory measures. The Council may issue additional guidance for public comment regarding potential additional metrics and thresholds relevant to asset manager determinations.

Generally, as reporting requirements evolve and new data about certain industries and nonbank financial companies become available, the Council expects to review the quantitative thresholds as appropriate based on this new information. For example, the Council's analysis will be informed by credit exposure data proposed to be collected under section 165 of the Dodd-Frank Act by the Federal Deposit Insurance Corporation and the Board of Governors. Similarly, pursuant to reporting and disclosure requirements being implemented under the Dodd-Frank Act, Council members will gain access to additional information through swap data repositories.

The Council recognizes that the proposed Stage 1 threshold to measure a nonbank financial company's derivative liabilities captures only the current exposure, rather than the current and potential future exposure created by the nonbank financial company's outstanding derivatives. The SEC and CFTC have proposed rules to define the terms ''major swap participant'' (''MSP'') and ''major security-based swap participant'' (''MSBSP'') that contain a methodology to measure the potential future exposure created by an entity's outstanding derivatives.

Once the final rules establishing the MSP and MSBSP definitions have been adopted, the rules regarding reporting of data on swaps and security-based swaps come into effect, and data have been collected pursuant to those rules, the

Council intends to establish a new Stage 1 threshold based on factors such as a nonbank financial company's current and potential future exposure from its outstanding derivatives for purposes of determining whether some or all MSPs, MSBSPs, or other firms will be subject to further examination in Stage 2.

In all instances, the Council reserves the right, in its discretion, to subject any nonbank financial company, irrespective of whether such company was identified in Stage 1, to further review, if the Council believes that further analysis of the company is warranted to determine if the company could pose a threat to U.S. financial stability.

After a subset of nonbank financial companies has been identified in Stage 1, the Council intends to conduct a robust analysis of the potential threat that each of those nonbank financial companies could pose to U.S. financial stability based on information available to the Council through existing public and regulatory sources, including information possessed by the company's primary financial regulatory agency or home country supervisor, as appropriate. In contrast to the application of uniform quantitative thresholds to a broad group of nonbank financial companies in Stage 1, the Council intends to evaluate the risk profile and characteristics of each individual nonbank financial company in Stage 2 based on a wide range of quantitative and qualitative industry- and company-specific factors. This analysis will use the six-category analytic framework described in section C above. In addition, the Stage 2 evaluation will include a review, based on available data, of whether the resolution of a nonbank financial company could pose a threat to U.S. financial stability.

Following Stage 2, nonbank financial companies that are selected for additional review will receive notice that they are being considered for a proposed determination and will be subject to further evaluation during Stage 3. As discussed in greater detail in the Proposed Guidance during the Stage 3 review, the Council intends to conduct an in-depth analysis of the nonbank financial company's potential to pose a threat to financial stability based on information obtained directly from the nonbank financial company and the information previously obtained by the Council during prior stages of review. The Council believes that in this stage of the evaluation, the Council likely will consider qualitative factors, including considerations that could mitigate or aggravate the potential of a nonbank financial company to pose a threat to U.S. financial stability, such as the nonbank financial company's resolvability, the opacity of the nonbank financial company's operations, its complexity, and the extent to which the nonbank financial company is subject to existing regulatory scrutiny and the nature of such scrutiny.

Based on the analysis performed in Stages 2 and 3, the Council may consider whether to determine, by vote, to subject any of the nonbank financial companies to a proposed determination. Prior to making a proposed determination, the Council may (i) consult with the nonbank financial company's primary financial regulatory agency or home country supervisor, as appropriate and (ii) consider the views of such entities.[9]

Following a proposed determination, the Council intends to issue a written notice of the proposed determination to the nonbank financial company that would provide an explanation of the basis of the proposed determination. The nonbank financial company may request a hearing to contest the proposed determination in accordance with section 113(e) of the Dodd-Frank Act and section 1310.21(c) of the Proposed Rule. The Council has provided additional details regarding the hearing process in the Proposed Rule and in the Proposed Guidance.

E. Section-by-Section Analysis

I. Subpart A General

A. Section 1310.1 Authority and purpose

This section sets forth the authority for and purpose of the Proposed Rule.

B. Section 1310.2 Definitions

This section defines the terms relevant to the Proposed Rule. It retains the majority of the definitions proposed in the NPR, with some technical modifications. For instance, the definition of ''predominantly engaged in financial activities'' has been incorporated into the definitions of ''U.S. nonbank financial company'' and ''foreign nonbank financial company'' to clarify that such definition is relevant for purposes of determining whether an entity meets the definition of U.S. nonbank financial company or foreign nonbank financial company. It also introduces definitions not set forth in the NPR, including definitions of ''Federal Insurance Office,'' ''hearing date,'' ''nonbank financial company,'' and ''Office of Financial Research.''

II. Subpart B Determinations

A. Section 1310.10 Council Determinations Regarding Nonbank Financial Companies

This section sets forth the Council's authority to make proposed and final determinations with respect to nonbank financial companies, pursuant to sections 113(a) and (b) of the Dodd-Frank Act. It sets forth the two standards for determinations the requirements for a Council vote with respect to proposed and final determinations and the Council's ability pursuant to section 112(d)(4) of the Dodd-Frank Act to request that the Board of Governors conduct an examination to determine whether a U.S. nonbank financial company should be supervised by the Board of Governors for purposes of Title I of the Dodd-Frank Act. Certain provisions included in the corresponding section in the NPR have been moved to other sections of the Proposed Rule for organizational purposes.

B. Section 1310.11 Considerations in Making Proposed and Final Determinations

This section sets forth the considerations that the Council must consider in making a proposed or final determination with respect to a U.S. nonbank financial company or foreign nonbank financial company. These considerations reflect the statutory factors set forth in sections 113(a)(2) and (b)(2) of the Dodd-Frank Act.

C. Section 1310.12 Anti-Evasion Provision

This section sets forth the Council's authority to require that the financial activities of a company that is not a nonbank financial company be supervised by the Board of Governors and be subject to prudential standards, if the Council determines that material financial distress related to, or the nature, scope, size, scale, concentration, interconnectedness, or mix of, the financial activities conducted directly or indirectly by a company would pose a threat to the financial stability of the United States, and the company is organized or operates in such a manner as to evade the application of Title I of the Dodd-Frank Act. This section defines ''financial activities'' as that term is defined in section 113(c)(5) of the Dodd-Frank Act.

[9] However, the Council does not believe that the concurrence of the primary financial regulatory agency is required prior to the Council's subjecting a nonbank financial company to a proposed determination. The Council's consultation with a nonbank financial company's primary financial regulatory agency does not create any rights on the part of the nonbank financial company under consideration.

This section is intended to clarify the application of subpart C as previously set forth in the NPR. This section provides that, in accordance with section 113(c)(4) of the Dodd-Frank Act, the provisions of subpart C governing information collection (including the confidentiality provisions), consultation, notice and opportunity for an evidentiary hearing, emergency waivers or modifications, and reevaluation and rescission of determinations would apply in the context of the Council's anti-evasion authority. The information-collection authority of the Council with respect to companies in this context derives from the authority of the Council to receive information from the OFR, member agencies, and the Federal Insurance Office, and from the authority of the OFR on behalf of the Council, to require the submission of periodic and other reports from any financial company under sections 112(d)(1) and (2) and 154(b) of the Dodd-Frank Act, respectively.

The provision in the corresponding section in the NPR relating to the establishment of an intermediate holding company was deleted because it related to authority of the Board of Governors rather than of the Council.

III. Subpart C Information Collection; Proposed and Final Determinations; Evidentiary Hearings

A. Section 1310.20 Council Information Collection; Consultation; Coordination; Confidentiality

This section sets forth the Council's authority to collect information with respect to nonbank financial companies and its responsibilities in consulting and coordinating with regulators and maintaining the confidentiality of submitted information. Paragraph (a) sets forth the Council's ability to collect information from the OFR, member agencies, the Federal Insurance Office, and other Federal and State financial regulatory agencies, and paragraph (b) sets forth the Council's ability to collect information from nonbank financial companies. These two paragraphs implement the provisions of section 112(d) of the Dodd-Frank Act relating to the Council's authority to obtain information and collect financial data. Paragraph (c) provides that the Council will consult with a nonbank financial company's primary financial regulatory agency in a timely manner, in accordance with section 113(g) of the Dodd-Frank Act. Paragraph (d) provides that the Council will consult with appropriate foreign regulatory authorities, to the extent appropriate, in accordance with section 113(i) of the Dodd-Frank Act. The NPR included provisions similar to paragraphs (c) and (d) of the Proposed Rule that were located elsewhere in the NPR. Paragraph (e), which was not included in the NPR, implements the confidentiality requirements provided in section 112(d)(5) of the Dodd-Frank Act.

B. Section 1310.21 Notice and Opportunity for an Evidentiary Hearing; Proposed and Final Determinations

This section sets forth the procedural rights of a nonbank financial company being considered for a proposed or final determination, the time period within which the Council will act after it notifies the nonbank financial company that it is being considered for a proposed determination, and the nonbank financial company's rights to a hearing after a proposed determination. Paragraph (a) provides that the Council will deliver written notice to a nonbank financial company that it is being considered for a proposed determination and will provide the nonbank financial company an opportunity to submit written materials to contest the proposed determination. Paragraph (a) clarifies that the nonbank financial company may submit any written materials to contest the determination, including materials concerning whether the nonbank financial company meets the standards for a determination. This broadens the scope of materials that may be provided to contest a determination from the version proposed in the NPR. Paragraph (b) provides that the Council will provide a nonbank financial company with written notice of a proposed determination, including an explanation of the basis of the proposed determination. Paragraphs (c), (d), and (e) set forth the procedures for an evidentiary hearing following a proposed determination, pursuant to section 113(e) of the Dodd-Frank Act, and provides the time period within which the Council will make a final determination. These paragraphs also provide that the Council will make public any final determination that it makes.

Paragraph (f) sets forth the time period within which the Council may make a proposed determination with respect to a nonbank financial company that has received a notice of consideration of determination. Under paragraph (a)(3), the Council will notify a nonbank financial company that is being considered for a proposed determination of the date on which the Council deems its evidentiary record regarding that nonbank financial company to be complete. If the Council does not make a proposed determination with respect to that nonbank financial company within 180 days after that date, the Council will not make a proposed determination unless the Council issues a subsequent written notice of consideration of determination under paragraph (a) and thereafter complies with the other procedures set forth in that section. This paragraph was added to the Proposed Rule to provide clarity to a nonbank financial company that is subject to a notice of consideration of determination regarding the timing of any potential subsequent Council action.

C. Section 1310.22 Emergency Exception to § 1310.21

This section sets forth the process by which the Council may waive or modify any of the notice or other procedural requirements of the Proposed Rule if the Council determines that the waiver or modification is necessary or appropriate to prevent or mitigate threats posed by the nonbank financial company to the financial stability of the United States, pursuant to section 113(f) of the Dodd-Frank Act. This section provides that a nonbank financial company will receive notice of the waiver or modification and an opportunity for a hearing to contest the waiver or modification, and sets forth the process by which the Council will make and publicly announce its final determination. This section incorporates the statutory requirement that the Council consult with the appropriate home country supervisor, if any, of a foreign nonbank financial company considered for a determination under this section. This section also requires the Council to consult with the primary financial regulatory agency, if any, of a nonbank financial company in making a determination under this section. These consultations will be conducted in such time and manner as the Council may deem appropriate.

D. Section 1310.23 Council Reevaluation and Rescission of Determinations

This section sets forth the Council's statutory responsibility, pursuant to section 113(d) of the Dodd-Frank Act, to reevaluate currently effective determinations and rescind any determination if the Council determines that the nonbank financial company no longer meets the standards for determination.

The section in the NPR relating to judicial review of the Council's final determinations pursuant to section 113(h) of the Dodd-Frank Act was removed because it did not serve to

implement the Council's authority to make determinations.

IV. Regulatory Flexibility Act

It is hereby certified that this rule will not have a significant economic impact on a substantial number of small entities. The economic impact of this rule is not expected to be significant. The rule would apply only to nonbank financial companies that could pose a threat to the financial stability of the United States. Size is an important factor, although not the exclusive factor, in assessing whether a company could pose a threat to financial stability. The Council expects that few, if any, small companies (as defined for purposes of the Small Business Act) could pose a threat to financial stability. Therefore, the Council does not expect the rule to directly affect a substantial number of small entities. Accordingly, a regulatory flexibility analysis under the Regulatory Flexibility Act (5 U.S.C. 601–612) is not required.

V. Paperwork Reduction Act

The collection of information contained in this notice of proposed rulemaking has been submitted to the Office of Management and Budget in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)). Comments on the collection of information should be sent to the Office of Management and Budget, Attn: Desk Officer for the Financial Stability Oversight Council, Office of Information and Regulatory Affairs, Washington, DC 20503, with copies to George A. Sacco, Department of the Treasury, Washington, DC 20220. Comments on the collection of information must be received by December 19, 2011.

Comments are specifically requested concerning:

Whether the proposed collection of information is necessary for the proper performance of the functions of the Council, including whether the information will have practical utility;

The accuracy of the estimated burden associated with the proposed collection of information;

How the quality, utility, and clarity of the information to be collected may be enhanced;

How the burden of complying with the proposed collection of information may be minimized, including through the application of automated collection techniques or other forms of information technology; and

Estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

The collection of information in these proposed regulations are found in § 1310.20 and § 1310.21.

Estimated total annual reporting burden: 1,000 hours.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number assigned by the Office of Management and Budget.

VI. Executive Orders 12866 and 13563

Executive Orders 12866 and 13563 direct certain agencies to assess costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. This rule has been designated a ''significant regulatory action'' although not economically significant, under section 3(f) of Executive Order 12866. Accordingly, the rule has been reviewed by the Office of Management and Budget.

List of Subjects in 12 CFR Part 1310

Nonbank financial companies.

For the reasons set forth in the preamble, the Financial Stability Oversight Council proposes to add a new part 1310 to chapter XIII of Title 12 of the Code of Federal Regulations, to read as follows:

PART 1310—SUPERVISION AND REGULATION OF CERTAIN NONBANK FINANCIAL COMPANIES

Sec.

Subpart A—General

1310.1 Authority and purpose.
1310.2 Definitions.

Subpart B—Determinations

1310.10 Council determinations regarding nonbank financial companies.
1310.11 Considerations in making proposed and final determinations.
1310.12 Anti-evasion provision.

Subpart C—Information Collection; Proposed and Final Determinations; Evidentiary Hearings

1310.20 Council information collection; consultation; coordination; confidentiality.
1310.21 Notice and opportunity for an evidentiary hearing; proposed and final determinations.
1310.22 Emergency exception to § 1310.21.
1310.23 Council reevaluation and rescission of determinations.
Appendix to Part 1310—Financial Stability Oversight Council Guidance for Nonbank Financial Company Determinations.

Authority: 12 U.S.C. 5321; 12 U.S.C. 5322; 12 U.S.C. 5323.

Subpart A—General

§ 1310.1 Authority and purpose.

(a) *Authority.* This part is issued by the Financial Stability Oversight Council (Council) under sections 111, 112 and 113 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (''Dodd-Frank Act'') (12 U.S.C. 5321, 5322 and 5323).

(b) *Purpose.* The principal purposes of this part are to set forth the standards and procedures governing Council determinations under section 113 of the Dodd-Frank Act (12 U.S.C. 5323), including whether material financial distress at a nonbank financial company, or the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States, and whether a nonbank financial company shall be supervised by the Board of Governors and shall be subject to prudential standards in accordance with Title I of the Dodd-Frank Act.

§ 1310.2 Definitions.

The terms used in this part have the following meanings—

Board of Governors. The term ''Board of Governors'' means the Board of Governors of the Federal Reserve System.

Commission. The term ''Commission'' means the Securities and Exchange Commission, except in the context of the Commodity Futures Trading Commission.

Council. The term ''Council'' means the Financial Stability Oversight Council.

Federal Insurance Office. The term ''Federal Insurance Office'' means the office established within the Department of the Treasury by section 502(a) of the Dodd-Frank Act (31 U.S.C. 301 (note)).

Foreign nonbank financial company. The term ''foreign nonbank financial company'' means a company (other than a company that is, or is treated in the United States as, a bank holding company) that is—

(1) Incorporated or organized in a country other than the United States; and

(2) ''Predominantly engaged in financial activities,'' as that term is defined in section 102(a)(6) of the Dodd-

Frank Act (12 U.S.C. 5311(a)(6)) and pursuant to the requirements for determining if a company is predominantly engaged in financial activities as established by regulation of the Board of Governors pursuant to section 102(b) of the Dodd-Frank Act (12 U.S.C. 5311(b)), including through a branch in the United States.

Hearing date. The term ''hearing date'' means the latest of—

(1) The date on which the Council has received all of the written materials timely submitted by a nonbank financial company for a hearing that is conducted without oral testimony;

(2) The final date on which the Council or its representatives convene to hear oral testimony presented by a nonbank financial company pursuant to § 1310.21 or § 1310.22, as applicable; and

(3) The date on which the Council has received all of the written materials timely submitted by a nonbank financial company to supplement any oral testimony and materials presented by the nonbank financial company pursuant to § 1310.21 or § 1310.22, as applicable.

Member agency. The term ''member agency'' means an agency represented by a voting member of the Council under section 111(b)(1) of the Dodd-Frank Act (12 U.S.C. 5321).

Nonbank financial company. The term ''nonbank financial company'' means a U.S. nonbank financial company or a foreign nonbank financial company.

Office of Financial Research. The term ''Office of Financial Research'' means the office established within the Department of the Treasury by section 152 of the Dodd-Frank Act (12 U.S.C. 5342).

Primary financial regulatory agency. The term ''primary financial regulatory agency'' means—

(1) The appropriate Federal banking agency, with respect to institutions described in section 3(q) of the Federal Deposit Insurance Act (12 U.S.C. 1813(q)), except to the extent that an institution is or the activities of an institution are otherwise described in paragraph (2), (3), (4), or (5) of this definition;

(2) The Commission, with respect to—

(i) Any broker or dealer that is registered with the Commission under the Securities Exchange Act of 1934, with respect to the activities of the broker or dealer that require the broker or dealer to be registered under that Act;

(ii) Any investment company that is registered with the Commission under the Investment Company Act of 1940, with respect to the activities of the investment company that require the investment company to be registered under that Act;

(iii) Any investment adviser that is registered with the Commission under the Investment Advisers Act of 1940, with respect to the investment advisory activities of such company and activities that are incidental to such advisory activities;

(iv) Any clearing agency registered with the Commission under the Securities Exchange Act of 1934, with respect to the activities of the clearing agency that require the agency to be registered under such Act;

(v) Any nationally recognized statistical rating organization registered with the Commission under the Securities Exchange Act of 1934;

(vi) Any transfer agent registered with the Commission under the Securities Exchange Act of 1934;

(vii) Any exchange registered as a national securities exchange with the Commission under the Securities Exchange Act of 1934;

(viii) Any national securities association registered with the Commission under the Securities Exchange Act of 1934;

(ix) Any securities information processor registered with the Commission under the Securities Exchange Act of 1934;

(x) The Municipal Securities Rulemaking Board established under the Securities Exchange Act of 1934;

(xi) The Public Company Accounting Oversight Board established under the Sarbanes-Oxley Act of 2002 (15 U.S.C. 7210 *et seq.*);

(xii) The Securities Investor Protection Corporation established under the Securities Investor Protection Act of 1970 (15 U.S.C. 78aaa *et seq.*); and

(xiii) Any security-based swap execution facility, security-based swap data repository, security-based swap dealer or major security-based swap participant registered with the Commission under the Securities Exchange Act of 1934, with respect to the security-based swap activities of the person that require such person to be registered under such Act;

(3) The Commodity Futures Trading Commission, with respect to—

(i) Any futures commission merchant registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*), with respect to the activities of the futures commission merchant that require the futures commission merchant to be registered under that Act;

(ii) Any commodity pool operator registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*), with respect to the activities of the commodity pool operator that require the commodity pool operator to be registered under that Act, or a commodity pool, as defined in that Act;

(iii) Any commodity trading advisor or introducing broker registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*), with respect to the activities of the commodity trading advisor or introducing broker that require the commodity trading advisor or introducing broker to be registered under that Act;

(iv) Any derivatives clearing organization registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*), with respect to the activities of the derivatives clearing organization that require the derivatives clearing organization to be registered under that Act;

(v) Any board of trade designated as a contract market by the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*);

(vi) Any futures association registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*);

(vii) Any retail foreign exchange dealer registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*), with respect to the activities of the retail foreign exchange dealer that require the retail foreign exchange dealer to be registered under that Act;

(viii) Any swap execution facility, swap data repository, swap dealer, or major swap participant registered with the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 *et seq.*) with respect to the swap activities of the person that require such person to be registered under that Act; and

(ix) Any registered entity as defined in section 1a of the Commodity Exchange Act (7 U.S.C. 1a), with respect to the activities of the registered entity that require the registered entity to be registered under that Act;

(4) The State insurance authority of the State in which an insurance company is domiciled, with respect to the insurance activities and activities that are incidental to such insurance activities of an insurance company that is subject to supervision by the State

insurance authority under State insurance law; and

(5) The Federal Housing Finance Agency, with respect to Federal Home Loan Banks or the Federal Home Loan Bank System, and with respect to the Federal National Mortgage Association or the Federal Home Loan Mortgage Corporation.

Prudential standards. The term ''prudential standards'' means enhanced supervision and regulatory standards established by the Board of Governors under section 165 of the Dodd-Frank Act (12 U.S.C. 5365).

Significant companies. The terms ''significant nonbank financial company'' and ''significant bank holding company'' have the meanings ascribed to such terms by regulation of the Board of Governors issued under section 102(a)(7) of the Dodd-Frank Act (12 U.S.C. 5311(a)(7)).

U.S. nonbank financial company. The term ''U.S. nonbank financial company'' means a company (other than a bank holding company; a Farm Credit System institution chartered and subject to the provisions of the Farm Credit Act of 1971 (12 U.S.C. 2001 *et seq.*); a national securities exchange (or parent thereof), clearing agency (or parent thereof, unless the parent is a bank holding company), security-based swap execution facility, or security-based swap data repository registered with the Commission; a board of trade designated as a contract market by the Commodity Futures Trading Commission (or parent thereof); or a derivatives clearing organization (or parent thereof, unless the parent is a bank holding company), swap execution facility, or swap data repository registered with the Commodity Futures Trading Commission), that is—

(1) Incorporated or organized under the laws of the United States or any State; and

(2) ''Predominantly engaged in financial activities,'' as that term is defined in section 102(a)(6) of the Dodd-Frank Act (12 U.S.C. 5311(a)(6)), and pursuant to the requirements for determining if a company is predominantly engaged in financial activities as established by regulation of the Board of Governors pursuant to section 102(b) of the Dodd-Frank Act (12 U.S.C. 5311(b)).

Subpart B—Determinations

§ 1310.10 Council determinations regarding nonbank financial companies.

(a) *Determinations.* The Council may determine that a nonbank financial company shall be supervised by the Board of Governors and shall be subject to prudential standards, in accordance with Title I of the Dodd-Frank Act, if the Council determines that material financial distress at the nonbank financial company, or the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States.

(b) *Vote required.* Any proposed or final determination under paragraph (a) of this section shall—

(1) Be made by the Council and shall not be delegated by the Council; and

(2) Require the vote of not fewer than two-thirds of the voting members of the Council then serving, including the affirmative vote of the Chairperson of the Council.

(c) *Back-up examination by the Board of Governors.*

(1) If the Council is unable to determine whether the financial activities of a U.S. nonbank financial company, including a U.S. nonbank financial company that is owned by a foreign nonbank financial company, pose a threat to the financial stability of the United States, based on information or reports obtained by the Council under § 1310.20, including discussions with management, and publicly available information, the Council may request the Board of Governors, and the Board of Governors is authorized, to conduct an examination of the U.S. nonbank financial company and its subsidiaries for the sole purpose of determining whether the nonbank financial company should be supervised by the Board of Governors for purposes of Title I of the Dodd-Frank Act (12 U.S.C. 5311–5374).

(2) The Council shall review the results of the examination of a nonbank financial company (including its subsidiaries) conducted by the Board of Governors under this paragraph (c) in connection with any proposed or final determination under paragraph (a) of this section with respect to the nonbank financial company.

§ 1310.11 Considerations in making proposed and final determinations.

(a) *Considerations for U.S. nonbank financial companies.* In making a proposed or final determination under § 1310.10(a) with respect to a U.S. nonbank financial company, the Council shall consider—

(1) The extent of the leverage of the U.S. nonbank financial company and its subsidiaries;

(2) The extent and nature of the off-balance-sheet exposures of the U.S. nonbank financial company and its subsidiaries;

(3) The extent and nature of the transactions and relationships of the U.S. nonbank financial company and its subsidiaries with other significant nonbank financial companies and significant bank holding companies;

(4) The importance of the U.S. nonbank financial company and its subsidiaries as a source of credit for households, businesses, and State and local governments and as a source of liquidity for the United States financial system;

(5) The importance of the U.S. nonbank financial company and its subsidiaries as a source of credit for low-income, minority, or underserved communities, and the impact that the failure of such U.S. nonbank financial company would have on the availability of credit in such communities;

(6) The extent to which assets are managed rather than owned by the U.S. nonbank financial company and its subsidiaries, and the extent to which ownership of assets under management is diffuse;

(7) The nature, scope, size, scale, concentration, interconnectedness, and mix of the activities of the U.S. nonbank financial company and its subsidiaries;

(8) The degree to which the U.S. nonbank financial company and its subsidiaries are already regulated by 1 or more primary financial regulatory agencies;

(9) The amount and nature of the financial assets of the U.S. nonbank financial company and its subsidiaries;

(10) The amount and types of the liabilities of the U.S. nonbank financial company and its subsidiaries, including the degree of reliance on short-term funding; and

(11) Any other risk-related factor that the Council deems appropriate, either by regulation or on a case-by-case basis.

(b) *Considerations for foreign nonbank financial companies.* In making a proposed or final determination under § 1310.10(a) with respect to a foreign nonbank financial company, the Council shall consider—

(1) The extent of the leverage of the foreign nonbank financial company and its subsidiaries;

(2) The extent and nature of the United States related off-balance-sheet exposures of the foreign nonbank financial company and its subsidiaries;

(3) The extent and nature of the transactions and relationships of the foreign nonbank financial company and its subsidiaries with other significant nonbank financial companies and significant bank holding companies;

(4) The importance of the foreign nonbank financial company and its subsidiaries as a source of credit for

United States households, businesses, and State and local governments and as a source of liquidity for the United States financial system;

(5) The importance of the foreign nonbank financial company and its subsidiaries as a source of credit for low-income, minority, or underserved communities in the United States, and the impact that the failure of such foreign nonbank financial company would have on the availability of credit in such communities;

(6) The extent to which assets are managed rather than owned by the foreign nonbank financial company and its subsidiaries and the extent to which ownership of assets under management is diffuse;

(7) The nature, scope, size, scale, concentration, interconnectedness, and mix of the activities of the foreign nonbank financial company and its subsidiaries;

(8) The extent to which the foreign nonbank financial company and its subsidiaries are subject to prudential standards on a consolidated basis in the foreign nonbank financial company's home country that are administered and enforced by a comparable foreign supervisory authority;

(9) The amount and nature of the United States financial assets of the foreign nonbank financial company and its subsidiaries;

(10) The amount and nature of the liabilities of the foreign nonbank financial company and its subsidiaries used to fund activities and operations in the United States, including the degree of reliance on short-term funding; and

(11) Any other risk-related factor that the Council deems appropriate, either by regulation or on a case-by-case basis.

§ 1310.12 Anti-evasion provision.

(a) *Determinations.* In order to avoid evasion of Title I of the Dodd-Frank Act (12 U.S.C. 5311–5374) or this part, the Council, on its own initiative or at the request of the Board of Governors, may require that the financial activities of a company shall be supervised by the Board of Governors and subject to prudential standards if the Council determines that—

(1) Material financial distress related to, or the nature, scope, size, scale, concentration, interconnectedness, or mix of, the financial activities conducted directly or indirectly by a company incorporated or organized under the laws of the United States or any State or the financial activities in the United States of a company incorporated or organized in a country other than the United States would pose a threat to the financial stability of the United States, based on consideration of the factors in—

(i) § 1310.11(a) if the company is incorporated or organized under the laws of the United States or any State; or

(ii) § 1310.11(b) if the company is incorporated or organized in a country other than the United States; and

(2) The company is organized or operates in such a manner as to evade the application of Title I of the Dodd-Frank Act (12 U.S.C. 5311–5374) or this part.

(b) *Vote required.* Any proposed or final determination under paragraph (a) of this section shall—

(1) Be made by the Council and shall not be delegated by the Council; and

(2) Require the vote of not fewer than two-thirds of the voting members of the Council then serving, including the affirmative vote of the Chairperson of the Council.

(c) *Definition of covered financial activities.* For purposes of this section, the term ''financial activities''—

(1) Means activities that are financial in nature (as defined in section 4(k) of the Bank Holding Company Act of 1956);

(2) Includes the ownership or control of one or more insured depository institutions; and

(3) Does not include internal financial activities conducted for the company or any affiliate thereof, including internal treasury, investment, and employee benefit functions.

(d) *Application of other provisions.* Sections 1310.20(a), 1310.20(b), 1310.20(c), 1310.20(e), 1310.21, 1310.22, and 1310.23, and the definitions referred to therein, shall apply to proposed and final determinations of the Council with respect to the financial activities of a company pursuant to this section in the same manner as such sections apply to proposed and final determinations of the Council with respect to nonbank financial companies.

Subpart C—Information Collection; Proposed and Final Determinations; Evidentiary Hearings

§ 1310.20 Council information collection; consultation; coordination; confidentiality.

(a) *Information collection from the Office of Financial Research, member agencies, the Federal Insurance Office, and other Federal and State financial regulatory agencies.* The Council may receive, and may request the submission of, such data or information from the Office of Financial Research, member agencies, the Federal Insurance Office, and other Federal and State financial regulatory agencies as the Council deems necessary to carry out the provisions of Title I of the Dodd-Frank Act (12 U.S.C. 5311–5374) or this part.

(b) *Information collection from nonbank financial companies.*

(1) The Council may, to the extent the Council determines appropriate, direct the Office of Financial Research to require the submission of periodic and other reports from any nonbank financial company, including a nonbank financial company that is being considered for a proposed or final determination under § 1310.10(a), for the purpose of assessing the extent to which a nonbank financial company poses a threat to the financial stability of the United States.

(2) Before requiring the submission of reports under this paragraph (b) from any nonbank financial company that is regulated by a member agency or any primary financial regulatory agency, the Council, acting through the Office of Financial Research, shall coordinate with such agency or agencies and shall, whenever possible, rely on information available from the Office of Financial Research or such agency or agencies.

(3) Before requiring the submission of reports under this paragraph (b) from a company that is a foreign nonbank financial company, the Council shall, acting through the Office of Financial Research, to the extent appropriate, consult with the appropriate foreign regulator of such foreign nonbank financial company and, whenever possible, rely on information already being collected by such foreign regulator, with English translation.

(c) *Consultation.* The Council shall consult with the primary financial regulatory agency, if any, for each nonbank financial company that is being considered for supervision by the Board of Governors under § 1310.10(a) and with the primary financial regulatory agency, if any, of any subsidiary of such nonbank financial company, in a timely manner before the Council makes any final determination under § 1310.10(a) with respect to such nonbank financial company.

(d) *International coordination.* In exercising its duties under this part with respect to foreign nonbank financial companies and cross-border activities and markets, the Council, acting through its Chairperson or other authorized designee, shall consult with appropriate foreign regulatory authorities, to the extent appropriate.

(e) *Confidentiality*—(1) *In general.* The Council shall maintain the confidentiality of any data, information, and reports submitted under this part.

(2) *Retention of privilege.* The submission of any non–publicly available data or information under this part shall not constitute a waiver of, or otherwise affect, any privilege arising under Federal or State law (including the rules of any Federal or State court) to which the data or information is otherwise subject.

(3) *Freedom of Information Act.* Section 552 of Title 5, United States Code, including the exceptions thereunder, shall apply to any data or information submitted under this part.

§ 1310.21 Notice and opportunity for an evidentiary hearing; proposed and final determinations.

(a) *Written notice of consideration of determination; submission of materials.* Before providing a nonbank financial company written notice of a proposed determination pursuant to paragraph (b) of this section, the Council shall provide the nonbank financial company—

(1) Written notice that the Council is considering whether to make a proposed determination with respect to the nonbank financial company under § 1310.10(a);

(2) An opportunity to submit written materials, within such time as the Council determines to be appropriate, to the Council to contest the Council's consideration of the nonbank financial company for a proposed determination, including materials concerning whether, in the nonbank financial company's view, material financial distress at the nonbank financial company, or the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States; and

(3) Notice when the Council deems its evidentiary record regarding such nonbank financial company to be complete.

(b) *Notice of proposed determination.* If the Council determines under § 1310.10(a) that a nonbank financial company should be supervised by the Board of Governors and be subject to prudential standards, the Council shall provide to the nonbank financial company written notice of the proposed determination, including an explanation of the basis of the proposed determination and the date by which an evidentiary hearing may be requested by the nonbank financial company under paragraph (c) of this section.

(c) *Evidentiary hearing.*

(1) Not later than 30 days after the date of receipt by a nonbank financial company of the notice of proposed determination under paragraph (b) of this section, the nonbank financial company may request, in writing, an opportunity for a written or oral evidentiary hearing before the Council to contest the proposed determination under § 1310.10(a).

(2) Upon receipt by the Council of a timely request under paragraph (c)(1), the Council shall fix a time (not later than 30 days after the date of receipt by the Council of the request) and place at which such nonbank financial company may appear, personally or through counsel, for an evidentiary hearing at which the nonbank financial company may submit written materials (or, at the sole discretion of the Council, oral testimony and oral argument) to contest the proposed determination under § 1310.10(a), including materials concerning whether, in the nonbank financial company's view, material financial distress at the nonbank financial company, or the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States.

(d) *Final determination after evidentiary hearing.* If the nonbank financial company makes a timely request for an evidentiary hearing under paragraph (c) of this section, the Council shall, not later than 60 days after the hearing date—

(1) Make a final determination under § 1310.10(a);

(2) Notify the nonbank financial company, in writing, of the final determination of the Council, which notice shall contain a statement of the basis for the decision of the Council; and

(3) Publicly announce the final determination of the Council.

(e) *No evidentiary hearing requested.* If a nonbank financial company does not make a timely request for an evidentiary hearing under paragraph (c) of this section or notifies the Council in writing that it is not requesting an evidentiary hearing under paragraph (c) of this section, the Council shall, not later than 10 days after the date by which the nonbank financial company could have requested a hearing under paragraph (c) of this section or 10 days after the date on which the Council receives notice from the nonbank financial company that it is not requesting an evidentiary hearing, as applicable—

(1) Make a final determination under § 1310.10(a);

(2) Notify the nonbank financial company, in writing, of the final determination of the Council, which notice shall contain a statement of the basis for the decision of the Council; and

(3) Publicly announce the final determination of the Council.

(f) *Time period for consideration.*

(1) If the Council does not make a proposed determination under § 1310.10(a) with respect to a nonbank financial company within 180 days after the date on which the nonbank financial company receives the notice of completion of the Council's evidentiary record described in paragraph (a)(3) of this section, the nonbank financial company shall not be eligible for a proposed determination under § 1310.10(a) unless the Council issues a subsequent written notice of consideration of determination under paragraph (a) of this section to such nonbank financial company.

(2) This paragraph (f) shall not limit the Council's ability to issue a subsequent written notice of consideration of determination under § 1310.21(a) to any nonbank financial company that, within 180 days after the date on which such nonbank financial company received a notice described in paragraph (a)(3) of this section, does not become subject to a proposed determination under § 1310.10(a).

§ 1310.22 Emergency exception to § 1310.21.

(a) *Exception to § 1310.21.* Notwithstanding anything to the contrary in § 1310.21, the Council may waive or modify any or all of the notice and other procedural requirements of § 1310.21 with respect to a nonbank financial company if—

(1) The Council determines that such waiver or modification is necessary or appropriate to prevent or mitigate threats posed by the nonbank financial company to the financial stability of the United States; and

(2) The Council provides written notice of the waiver or modification under this section to the nonbank financial company as soon as practicable, but not later than 24 hours after the waiver or modification is granted. Any such notice shall set forth the manner and form for transmitting a request for an evidentiary hearing under paragraph (c) of this section.

(b) *Consultation.*

(1) In making a determination under paragraph (a) of this section with respect to a nonbank financial company, the Council shall consult with the primary financial regulatory agency, if any, for such nonbank financial company, in such time and manner as the Council may deem appropriate.

(2) In making a determination under paragraph (a) of this section with

respect to a foreign nonbank financial company, the Council shall consult with the appropriate home country supervisor, if any, of such foreign nonbank financial company, in such time and manner as the Council may deem appropriate.

(c) *Opportunity for evidentiary hearing.*

(1) If the Council, pursuant to paragraph (a) of this section, waives or modifies any of the notice or other procedural requirements of § 1310.21 with respect to a nonbank financial company, the nonbank financial company may request, in writing, an opportunity for a written or oral evidentiary hearing before the Council to contest such waiver or modification, not later than 10 days after the date of receipt by the nonbank financial company of the notice described in paragraph (a)(2) of this section.

(2) Upon receipt of a timely request for an evidentiary hearing under paragraph (c)(1), the Council shall fix a time (not later than 15 days after the date of receipt by the Council of the request) and place at which the nonbank financial company may appear, personally or through counsel, to submit written materials (or, at the sole discretion of the Council, oral testimony and oral argument) regarding the waiver or modification under this section.

(d) *Notice of final determination.* If the nonbank financial company makes a timely request for an evidentiary hearing under paragraph (c) of this section, the Council shall, not later than 30 days after the hearing date—

(1) Notify the nonbank financial company, in writing, of the final determination of the Council regarding the waiver or modification under this § 1310.22, which notice shall contain a statement of the basis for the final decision of the Council; and

(2) Publicly announce the final determination of the Council.

(e) *Vote required.* Any determination of the Council under paragraph (a)(1) of this section to waive or modify any of the notice or other procedural requirements of § 1310.21 shall—

(1) Be made by the Council and shall not be delegated by the Council; and

(2) Require the vote of not fewer than two-thirds of the voting members of the Council then serving, including the affirmative vote of the Chairperson of the Council.

§ 1310.23 Council reevaluation and rescission of determinations.

(a) *Reevaluation and rescission.* The Council shall, not less frequently than annually—

(1) Reevaluate each currently effective determination made under § 1310.10(a); and

(2) Rescind any such determination, if the Council determines that the nonbank financial company no longer meets the standard under § 1310.10(a), taking into account the considerations in § 1310.11(a) or § 1310.11(b), as applicable.

(b) *Vote required.* Any determination of the Council under paragraph (a)(2) of this section to rescind a determination made with respect to a nonbank financial company shall—

(1) Be made by the Council and shall not be delegated by the Council; and

(2) Require the vote of not fewer than two-thirds of the voting members of the Council then serving, including the affirmative vote of the Chairperson of the Council.

APPENDIX TO PART 1310—FINANCIAL STABILITY OVERSIGHT COUNCIL GUIDANCE FOR NONBANK FINANCIAL COMPANY DETERMINATIONS

I. Introduction

Section 113 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the ''Dodd-Frank Act'') authorizes the Financial Stability Oversight Council (the ''Council'') to determine that a nonbank financial company will be supervised by the Board of Governors of the Federal Reserve System (the ''Board of Governors'') and be subject to prudential standards in accordance with Title I of the Dodd-Frank Act if either of two standards is met. Under the first standard, the Council may subject a nonbank financial company to supervision by the Board of Governors and prudential standards if the Council determines that ''material financial distress'' at the nonbank financial company could pose a threat to the financial stability of the United States. Under the second standard, the Council may determine that a nonbank financial company will be supervised by the Board of Governors and subject to prudential standards if the nature, scope, size, scale, concentration, interconnectedness, or mix of the nonbank financial company's activities could pose a threat to U.S. financial stability. Section 113 of the Dodd-Frank Act also lists 10 considerations that the Council must take into account in making a determination.

Section II of this document describes the manner in which the Council intends to apply the statutory standards and considerations in making determinations under section 113 of the Dodd-Frank Act. First, section II defines ''threat to the financial stability of the United States'' and describes channels through which a nonbank financial company could pose such a threat. Second, it discusses each of the two statutory standards for determination. Third, it describes the six-category framework that the Council intends to use to evaluate nonbank financial companies under each of the 10 statutory considerations. Section II also includes a list of sample metrics that may be used to evaluate individual nonbank financial companies under each of the six categories.

Section III of this document outlines the process that the Council intends to follow in non-emergency situations when determining whether to subject a nonbank financial company to Board of Governors supervision and prudential standards. Section III also provides a detailed description of the analysis that the Council intends to conduct during each stage of its review. In the first stage of the process, the Council will apply six uniform quantitative thresholds to nonbank financial companies to identify those nonbank financial companies that will be subject to further evaluation by the Council. Because the Council is relying on quantitative thresholds using publicly available data in the first stage, nonbank financial companies should be able to assess whether they are likely to be subject to further evaluation by the Council. During the second stage of the evaluation process, the Council will analyze the identified nonbank financial companies using a broad range of information available to the Council primarily through existing public and regulatory sources. The third stage of the process will involve a comprehensive analysis of those nonbank financial companies using information collected directly from the nonbank financial company, as well as the information used in the first two stages.

II. Council Determination Authority and Proposed Framework

As noted above, the Council may determine that a nonbank financial company will be supervised by the Board of Governors and be subject to prudential standards if the Council determines that (i) material financial distress at the nonbank financial company could pose a threat to the financial stability of the United States (the ''First Determination Standard'') or (ii) the nature, scope, size, scale, concentration, interconnectedness, or mix of the activities of the nonbank financial company, could pose a threat to the financial stability of the United States (the ''Second Determination Standard,'' and, together with the First Determination Standard, the ''Determination Standards'').

This section provides definitions of the terms ''threat to the financial stability of the United States'' and ''material financial distress'' and describes how the Council expects to apply the Determination Standards.

a. Threat to the Financial Stability of the United States

The Determination Standards require the Council to determine whether a nonbank financial company could pose a threat to the financial stability of the United States. The Council will consider a ''threat to the financial stability of the United States'' to exist if there would be an impairment of financial intermediation or of financial market functioning that would be sufficiently severe to inflict significant damage on the broader economy.

An impairment of financial intermediation and financial market functioning can occur

through several channels. The Council has identified the following channels as most likely to facilitate the transmission of the negative effects of a nonbank financial company's material financial distress or activities to other financial firms and markets:

• *Exposure.* A nonbank financial company's creditors, counterparties, investors, or other market participants have exposure to the nonbank financial company that is significant enough to materially impair those creditors, counterparties, investors, or other market participants and thereby pose a threat to U.S. financial stability. In its initial analysis of nonbank financial companies with respect to this channel, the Council expects to consider metrics including total consolidated assets, credit default swaps outstanding, derivative liabilities, loans and bonds outstanding, and leverage ratio.

• *Asset liquidation.* A nonbank financial company holds assets that, if liquidated quickly, would significantly disrupt trading or funding in key markets or cause significant losses or funding problems for other firms with similar holdings due to falling asset prices. This channel would likely be most relevant for a nonbank financial company whose funding and liquid asset profile makes it likely that it would be forced to liquidate assets quickly when it comes under financial pressure. For example, this could be the case if a large nonbank financial company relies heavily on short-term funding. In its initial analysis of nonbank financial companies with respect to this channel, the Council expects to consider metrics including total consolidated assets and short-term debt ratio.

• *Critical function or service.* A nonbank financial company is no longer able or willing to provide a critical function or service that is relied upon by market participants and for which there are no ready substitutes. The analysis of this channel will incorporate a review of the competitive landscape for markets in which a nonbank financial company participates and for the services it provides (including the provision of liquidity to the U.S. financial system, the provision of credit to low-income, minority, or underserved communities or the provision of credit to households, businesses and state and local governments), the nonbank financial company's market share, and the ability of other firms to replace those services. Due to the unique ways in which a nonbank financial company may provide a critical function or service to the market, the Council expects to apply company-specific analyses with respect to this channel, rather than applying a broadly applicable quantitative metric.

The Council believes that the threat a nonbank financial company may pose to U.S. financial stability through the impairment of financial intermediation and financial market functioning is likely to be exacerbated if the nonbank financial company is sufficiently complex, opaque, or difficult to resolve in bankruptcy such that its resolution in bankruptcy would disrupt key markets or have a material adverse impact on other financial firms or markets.

The Council intends to continue to evaluate additional transmission channels, and may, in its discretion, consider other channels through which a nonbank financial company may transmit the negative effects of its material financial distress or activities and thereby pose a threat to U.S. financial stability.

b. First Determination Standard: Material Financial Distress

Under the First Determination Standard, the Council may subject a nonbank financial company to supervision by the Board of Governors and prudential standards if the Council determines that ''material financial distress'' at the nonbank financial company could pose a threat to U.S. financial stability. The Council believes that material financial distress exists when a nonbank financial company is in imminent danger of insolvency or defaulting on its financial obligations.

For purposes of considering whether a nonbank financial company could pose a threat to U.S. financial stability under this Determination Standard, the Council intends to assess the impact of the nonbank financial company's material financial distress in the context of a period of overall stress in the financial services industry and in a weak macroeconomic environment. The Council believes this is appropriate because in such a context, a nonbank financial company's distress may have a greater effect on U.S. financial stability.

c. Second Determination Standard: Nature, Scope, Size, Scale, Concentration, Interconnectedness, or Mix of Activities

Under the Second Determination Standard, the Council may subject a nonbank financial company to supervision by the Board of Governors and prudential standards if the Council determines that the nature, scope, size, scale, concentration, interconnectedness, or mix of the nonbank financial company's activities could pose a threat to U.S. financial stability. The Council believes that this Determination Standard will be met if the Council determines that the nature of a nonbank financial company's business practices, conduct, or operations could pose a threat to U.S. financial stability, regardless of whether the nonbank financial company is experiencing financial distress. The Council expects that there likely will be significant overlap between the outcome of an assessment of a nonbank financial company under the First and Second Determination Standards, because, in many cases, a nonbank financial company that could pose a threat to U.S. financial stability because of the nature, scope, size, scale, concentration, interconnectedness, or mix of its activities could also pose a threat to U.S. financial stability if it were to experience material financial distress.

d. Analytic Framework for Statutory Considerations

As required by section 113 of the Dodd-Frank Act, the Council's determination will be based on its judgment that a firm meets one of the Determination Standards described above. In evaluating whether a firm meets one of the Determination Standards, the Council will consider each of the statutory considerations set forth in the statute. The discussion below outlines the analytic framework that the Council intends to use to organize its evaluation of a nonbank financial company under the statutory considerations and provides additional detail on the key data and analyses that the Council intends to use to assess the considerations.

1. Grouping of Statutory Considerations Into Six-Category Framework

The Dodd-Frank Act requires the Council to consider 10 considerations (described below) when evaluating the potential of a nonbank financial company to pose a threat to U.S. financial stability. The statute also authorizes the Council to consider ''any other risk-related factors that the Council deems appropriate.'' These statutory considerations will help the Council to evaluate whether one of the Determination Standards, as described in sections II.b and II.c above, has been met. The Council has developed an analytic framework that groups all relevant factors, including the 10 statutory considerations and any additional risk-related factors, into six categories: size, interconnectedness, lack of substitutes, leverage, liquidity risk and maturity mismatch, and existing regulatory scrutiny. The Council expects to use these six categories to guide its evaluation of whether a particular nonbank financial company meets either Determination Standard. However, the Council's ultimate determination decision regarding a nonbank financial company will not be based on a formulaic application of the six categories. Rather, the Council intends to analyze a nonbank financial company using quantitative and qualitative data relevant to each of the six categories, as the Council determines is appropriate with respect to a particular nonbank financial company.

Each of the six categories reflects a different dimension of a nonbank financial company's potential to pose a threat to U.S. financial stability. Three of the six categories—size, substitutability and interconnectedness—seek to assess the potential impact of the nonbank financial company's financial distress on the broader economy. Material financial distress at nonbank financial companies that are large, provide critical financial services for which there are few substitutes, or are highly interconnected with other financial firms or markets are more likely to have a financial or operational impact on other companies, markets, and consumers that could pose a threat to the financial stability of the United States. The remaining three categories—leverage, liquidity risk and maturity mismatch, and existing regulatory scrutiny of the nonbank financial company—seek to assess the vulnerability of a nonbank financial company to financial distress. Nonbank financial companies that are highly leveraged, have a high degree of liquidity risk or maturity mismatch, and are under little or no regulatory scrutiny are more likely to be more vulnerable to financial distress.

Each of the statutory considerations in sections 113(a)(2) and (b)(2) of the Dodd-Frank Act would be considered as part of one or more of the six categories. This is reflected in the following table, using the

considerations relevant to a U.S. nonbank financial company for illustrative purposes.[10]

Statutory considerations:	Category or categories in which this consideration would be addressed:
(A) The extent of the leverage of the company	Leverage.
(B) The extent and nature of the off-balance-sheet exposures of the company.	Size; interconnectedness.
(C) The extent and nature of the transactions and relationships of the company with other significant nonbank financial companies and significant bank holding companies.	Interconnectedness.
(D) The importance of the company as a source of credit for households, businesses, and State and local governments and as a source of liquidity for the United States financial system.	Size; lack of substitutes.
(E) The importance of the company as a source of credit for low-income, minority, or underserved communities, and the impact that the failure of such company would have on the availability of credit in such communities.	Lack of substitutes.
(F) The extent to which assets are managed rather than owned by the company, and the extent to which ownership of assets under management is diffuse.	Size; interconnectedness; lack of substitutes.
(G) The nature, scope, size, scale, concentration, interconnectedness, and mix of the activities of the company.	Size; interconnectedness; lack of substitutes.
(H) The degree to which the company is already regulated by 1 or more primary financial regulatory agencies.	Existing regulatory scrutiny.
(I) The amount and nature of the financial assets of the company	Size; interconnectedness.
(J) The amount and types of the liabilities of the company, including the degree of reliance on short-term funding.	Liquidity risk and maturity mismatch; size; interconnectedness.
(K) Any other risk-related factors that the Council deems appropriate	Appropriate category or categories based on the nature of the additional risk-related factor.

2. Six-Category Framework

The discussion below describes each of the six categories and how these categories relate to a firm's likelihood to pose a threat to financial stability. The sample metrics set forth below under each category are representative, not exhaustive, and may not apply to all nonbank financial companies under evaluation. The Council may apply the sample metrics in the context of stressed market conditions.

Interconnectedness

Interconnectedness captures direct or indirect linkages between financial companies that may be conduits for the transmission of the effects resulting from a nonbank financial company's material financial distress or activities. Examples of the key conduits through which the effects may travel are a nonbank financial company's direct or indirect exposures to counterparties (including creditors, trading and derivatives counterparties, investors, borrowers, and other participants in the financial markets). Interconnectedness depends not only on the number of counterparties that a nonbank financial company has, but also on the importance of that nonbank financial company to its counterparties and the extent to which the counterparties are interconnected with other financial firms, the financial system and the broader economy. The Council's assessment of interconnectedness is intended to determine whether a nonbank financial company's exposure to its counterparties would pose a threat to U.S. financial stability if that company encountered material financial distress.

For example, metrics that may be used to assess interconnectedness include:

- Counterparties' exposures to a nonbank financial company, including derivatives, reinsurance, loans, securities borrowing and lending, and lines of credit that facilitate settlement and clearing activities.
- Number, size, and financial strength of a nonbank financial company's counterparties, including the proportion of its counterparties' exposure to the nonbank financial company relative to the counterparties' capital.
- Identity of a nonbank financial company's principal contractual counterparties, which reflects the concentration of the nonbank financial company's assets financed by particular firms and the importance of the nonbank financial company's counterparties to the market.
- Aggregate amounts of a nonbank financial company's gross or net derivatives exposures and the number of its derivatives counterparties.
- The amount of gross notional credit default swaps outstanding for which a nonbank financial company is the reference entity.
- Outstanding loans borrowed and bonds issued, which captures a nonbank financial company's sources of funding.
- Reinsurance obligations, which measure the reinsurance risk assumed from non-affiliates net of retrocession.

Substitutability

Substitutability captures the extent to which other firms could provide similar financial services in a timely manner at a similar price and quantity if a nonbank financial company withdraws from a particular market. Substitutability also captures situations in which a nonbank financial company is the primary or dominant provider of services in a market that the Council determines to be essential to U.S. financial stability. An example of the manner in which the Council may determine a nonbank financial company's substitutability is to consider its market share. The Council's evaluation of a nonbank financial company's market share regarding a particular product or service will include assessments of the ability of the nonbank financial company's competitors to expand to meet market needs; the costs that market participants would incur if forced to switch providers; the timeframe within which a disruption in the provision of the product or service would materially affect market participants or market functioning; and the economic implications of such a disruption. Concern about a potential lack of substitutability could be greater if a nonbank financial company and its competitors are likely to experience stress at the same time because they are exposed to the same risks. The Council may also analyze a nonbank financial company's core operations and critical functions and the importance of those operations and functions to the U.S. financial system and assess how those operations and functions would be performed by the nonbank financial company or other market participants in the event of the nonbank financial company's material financial distress. The Council also intends to consider substitutability with respect to any nonbank financial company with global operations to identify the substitutability of critical market functions that the company provides in the United States in the event of material

[10] The corresponding statutory considerations for a foreign nonbank financial company would be considered under the relevant categories indicated in the table.

financial distress of a foreign parent company.

For example, metrics that may be used to assess substitutability include:

- The market share, using the appropriate quantitative measure (such as loans originated, loans outstanding, and notional transaction volume) of a nonbank financial company and its competitors in the market under consideration.
- The stability of market share across the firms in the market over time.
- The market share of the company and its competitors for products or services that serve a substantially similar economic function as the primary market under consideration.

Size

Size captures the amount of financial services or financial intermediation that a nonbank financial company provides. Size also may affect the extent to which the effects of a nonbank financial company's financial distress are transmitted to other firms and to the financial system. For example, financial distress at an extremely large nonbank financial company that is highly interconnected likely would transmit risk on a larger scale than would financial distress at a smaller nonbank financial company that is similarly interconnected. Size is conventionally measured by the assets, liabilities and capital of the firm. However, such measures of size may not provide complete or accurate assessments of the scale of a nonbank financial company's risk potential. Thus, the Council also intends to take into account off-balance sheet assets and liabilities and assets under management in a manner that recognizes the unique and distinct nature of these classes. Other measures of size, such as numbers of customers and counterparties, may also be relevant.

For example, metrics that may be used to assess size include:

- Total consolidated assets or liabilities, as determined under the applicable financial reporting standards.
- Total risk-weighted assets, as appropriate for different industry sectors.
- Off-balance sheet exposures where a nonbank financial company has a risk of loss, including, for example, lines of credit. For foreign nonbank financial companies, this would be evaluated based on the extent and nature of U.S.-related off-balance sheet exposures.
- The extent to which assets are managed rather than owned by a nonbank financial company and the extent to which ownership of assets under management is diffuse.
- Direct written premiums, as reported by insurance companies. This is the aggregate of direct written premiums reported by insurance entities under all lines of business and serves as a proxy for the amount of insurance underwritten by the insurance entities.
- Risk in force, which is the aggregate risk exposure from risk underwritten in insurance related to certain financial risks, such as mortgage insurance.
- Total loan originations, by loan type, in number and dollar amount.

Leverage

Leverage captures a company's exposure or risk in relation to its equity capital. Leverage amplifies a company's risk of financial distress in two ways. First, by increasing a company's exposure relative to capital, leverage raises the likelihood that a company will suffer losses exceeding its capital. Second, by increasing the size of a company's liabilities, leverage raises a company's dependence on its creditors' willingness and ability to fund its balance sheet. Leverage can also amplify the impact of a company's distress on other companies, both directly, by increasing the amount of exposure that other firms have to the company, and indirectly, by increasing the size of any asset liquidation that the company is forced to undertake as it comes under financial pressure. Leverage is typically measured by the ratio of debt to capital, but it can also be defined in terms of risk, as a measure of economic risk relative to capital. The latter measurement can better capture the effect of derivatives and other products with embedded leverage on the risk undertaken by a nonbank financial company.

For example, metrics that may be used to assess leverage include:

- Total assets and total debt measured relative to total equity, which is intended to measure financial leverage.
- Gross notional exposure of derivatives and off-balance sheet obligations relative to total equity or net assets under management, which is intended to show how much off-balance sheet leverage a nonbank financial company may have.
- The ratio of risk to statutory capital, which is relevant to certain insurance companies and is intended to show how much risk exposure a nonbank financial company has in relation to its ability to absorb loss.
- Changes in leverage ratios, which may indicate that a nonbank financial company is rapidly increasing its risk profile.

Liquidity Risk and Maturity Mismatch

Liquidity risk generally refers to the risk that a company may not have sufficient funding to satisfy its short-term needs, either through its cash flows, maturing assets, or assets salable at prices equivalent to book value, or through its ability to access funding markets. For example, if a company holds assets that are illiquid or that are subject to significant decreases in market value during times of market stress, the company may be unable to liquidate its assets effectively in response to a loss of funding. In order to assess liquidity, the Council may examine a nonbank financial company's assets to determine if it possesses cash instruments or readily marketable securities, such as Treasury securities, which could reasonably be expected to have a liquid market in times of distress. The Council may also review a nonbank financial company's debt profile to determine if it has adequate long-term funding, or can otherwise mitigate liquidity risk. Liquidity problems also can arise from a company's inability to roll maturing debt or to satisfy margin calls, and from demands for additional collateral, depositor withdrawals, draws on committed lines, and other potential draws on liquidity.

A maturity mismatch generally refers to the difference between the maturities of a company's assets and liabilities. A maturity mismatch affects a company's ability to survive a period of stress that may limit its access to funding and to withstand shocks in the yield curve. For example, if a company relies on short-term funding to finance longer-term positions, it will be subject to significant refunding risk that may force it to sell assets at low market prices or potentially suffer through significant margin pressure. However, maturity mismatches are not confined to the use of short-term liabilities and can exist at any point in the maturity schedule of a nonbank financial company's assets and liabilities. For example, in the case of a life insurance company, liabilities may have maturities of 30 years or more, whereas the market availability of equivalently long-term assets may be limited.

For example, metrics that may be used to assess liquidity and maturity mismatch include:

- Fraction of assets that are classified as level 2 and level 3 under applicable accounting standards, as a measure of how much of a nonbank financial company's balance sheet is composed of hard-to-value and potentially illiquid securities.
- Liquid asset ratios, which are intended to indicate a nonbank financial company's ability to repay its short-term debt.
- The ratio of unencumbered and highly liquid assets to the net cash outflows that a nonbank financial company could encounter in a short-term stress scenario.
- Callable debt as a fraction of total debt, which provides one measure of a nonbank financial company's ability to manage its funding position in response to changes in interest rates.
- Asset-backed funding versus other funding, to determine a nonbank financial company's susceptibility to distress in particular credit markets.
- Asset-liability duration and gap analysis, which is intended to indicate how well a nonbank financial company is matching the re-pricing and maturity of the nonbank financial company's assets and liabilities.
- Short-term debt as a percentage of total debt and as a percentage of total assets, which indicates a nonbank financial company's reliance on short-term debt markets.

Existing Regulatory Scrutiny

The Council will consider the extent to which nonbank financial companies are already subject to regulation, including the consistency of that regulation across nonbank financial companies within a sector, across different sectors, and providing similar services, and the statutory authority of those regulators. For example, the Council may consider whether a nonbank financial company is subject to consolidated supervision.

For example, metrics that may be used to assess existing regulatory scrutiny include:

- Existence of consolidated supervision, to determine whether non-regulated entities and groups within a nonbank financial company are supervised on a group-wide basis.

• For investment funds, whether the fund or manager is registered with the Securities and Exchange Commission, the Commodity Futures Trading Commission, or a bank or insurance regulator.

• For insurance companies, an assessment of the number of primary financial regulatory agencies and the number of ''lead state'' regulators.

• For entities based outside the United States, the extent to which a nonbank financial company is subject to prudential standards on a consolidated basis in its home country that are administered and enforced by a comparable foreign supervisory authority.

• Current regulatory bodies' ability to impose detailed and timely regulatory reporting obligations, capital or liquidity requirements, enforcement actions, and resolutions.

III. The Determination Process

The Council expects generally to follow a three-stage process of increasingly in-depth evaluation and analysis leading up to a proposed determination (a ''Proposed Determination'') that a nonbank financial company could pose a threat to the financial stability of the United States. Quantitative metrics, together with qualitative analysis, will inform the judgment of the Council when it is evaluating a nonbank financial company for a Proposed Determination. The purpose of this process is to help determine whether a nonbank financial company could pose a threat to the financial stability of the United States.

In the first stage of the process (''Stage 1''), a set of uniform quantitative metrics will be applied to a broad group of nonbank financial companies in order to identify nonbank financial companies for further evaluation and to provide clarity for nonbank financial companies that likely will not be subject to further evaluation. In Stage 1, the Council will rely solely on information available through existing public and regulatory sources. The purpose of Stage 1 is to enable the Council to identify a group of nonbank financial companies that are most likely to satisfy one of the Determination Standards.

In the second stage (''Stage 2''), the nonbank financial companies identified in Stage 1 will be analyzed and prioritized, based on a wide range of quantitative and qualitative information available to the Council primarily through public and regulatory sources. The Council will also begin the consultation process with the primary financial regulatory agencies or home country supervisors, as appropriate. During Stage 2, the Council intends to fulfill its statutory obligation to rely whenever possible on information available through the Office of Financial Research (the ''OFR'') or primary financial regulatory agencies before requiring the submission of reports from any nonbank financial company.[11]

Following Stage 2, nonbank financial companies that are selected for additional review will receive notice that they are being considered for a proposed determination and will be subject to in-depth evaluation during the third stage of review (''Stage 3''). Stage 3 will involve the evaluation of information collected directly from the nonbank financial company, in addition to the information considered during Stages 1 and 2. At the end of Stage 3, the Council may consider whether to make a Proposed Determination with respect to the nonbank financial company. If a Proposed Determination is made by the Council, the nonbank financial company may request a hearing in accordance with section 113(e) of the Dodd-Frank Act and section 1310.21(c) of the proposed rule.

The Council expects to follow this three-stage process and to consider the categories, metrics, thresholds, and channels described in this guidance to assess a nonbank financial company's potential to pose a threat to U.S. financial stability. In addition to the information described herein that the Council generally expects to consider, the Council also will consider quantitative and qualitative information that it deems relevant to a particular nonbank financial company, as each determination will be made on a company-specific basis. The Council may consider any nonbank financial company for a Proposed Determination at any point in the three-stage evaluation process described in this guidance if the Council believes such company could pose a threat to U.S. financial stability.

a. Stage 1: Initial Identification of Nonbank Financial Companies for Evaluation

In Stage 1, the Council will seek to identify a set of nonbank financial companies that merit company-specific evaluation. In this stage, the Council intends to apply quantitative thresholds to a broad group of nonbank financial companies. A nonbank financial company that is selected for further evaluation during Stage 1 will be further assessed during Stage 2. During the Stage 1 process, the Council will evaluate nonbank financial companies using data available to the Council, such as publicly available information and information member agencies possess in their supervisory capacities.

In the Stage 1 quantitative analysis, the Council intends to apply thresholds that relate to the framework categories of size, interconnectedness, leverage, and liquidity risk and maturity mismatch. These thresholds were selected based on (1) their applicability to nonbank financial companies that operate in different types of financial markets and industries, (2) the meaningful initial assessment that such thresholds provide regarding the potential for a nonbank financial company to pose a threat to financial stability in diverse financial markets, and (3) the current availability of data. These thresholds are intended to measure both the susceptibility of a nonbank financial company to financial distress and the potential for that nonbank financial company's financial distress to spread throughout the financial system. A nonbank financial company will be evaluated further in Stage 2 if it meets both the total consolidated assets threshold and any one of the other thresholds.[12] The thresholds are:

• *Total Consolidated Assets.* The Council intends to apply a size threshold of $50 billion in global total consolidated assets for U.S. nonbank financial companies or $50 billion in U.S. total consolidated assets for foreign nonbank financial companies. This threshold is consistent with the Dodd-Frank Act threshold of $50 billion in assets for subjecting bank holding companies to enhanced prudential standards.

• *Credit Default Swaps Outstanding.* The Council intends to apply a threshold of $30 billion in gross notional credit default swaps (''CDS'') outstanding for which a nonbank financial company is the reference entity. Gross notional value equals the sum of CDS contracts bought (or equivalently sold). If the amount of CDS sold on a particular nonbank financial company is greater than $30 billion, this indicates that a large number of institutions may be exposed to that nonbank financial company and that if the nonbank financial company fails, a significant number of financial market participants may be affected. This threshold was selected based on an analysis of the distribution of outstanding CDS data for nonbank financial companies included in a list of the top 1,000 CDS reference entities.

• *Derivative Liabilities.* The Council intends to apply a threshold of $3.5 billion of derivative liabilities. In accordance with Accounting Standards Codification 815, derivative liabilities equals the fair value of any derivatives contracts in a negative position after taking into account the effects of master netting agreements and cash collateral held with the same counterparty on a net basis, if elected. This threshold serves as a proxy for interconnectedness, as a nonbank financial company that has a greater level of derivatives liabilities would have higher counterparty exposure throughout the financial system.

• *Loans and Bonds Outstanding.* The Council intends to apply a threshold of $20 billion of outstanding loans borrowed and bonds issued. This threshold serves as a proxy for interconnectedness, as nonbank financial companies with a large amount of loans and bonds outstanding are generally more interconnected with the broader financial system, in part because financial institutions are the largest source of loans and hold a large proportion of bonds outstanding. An analysis of the distribution of total loans and bonds outstanding for a sample of nonbank financial companies was performed to determine the $20 billion threshold. Historical testing of this threshold demonstrated that it would have captured many of the nonbank financial companies that encountered material financial distress during the recent financial crisis, including Bear Stearns, Countrywide, and Lehman Brothers.

• *Leverage Ratio.* The Council intends to apply a threshold leverage ratio of total consolidated assets (excluding separate

[11] *See* 12 U.S.C. 5322(d)(3).

[12] For purposes of applying these six thresholds to investment funds managed by a nonbank financial company, the Council may consider the funds as a single entity if their investments are identical or highly similar.

accounts) to total equity of 15 to 1. The Council intends to exclude separate accounts from this calculation because separate accounts are not available to claims by general creditors of a nonbank financial company. Measuring leverage in this manner benefits from simplicity, availability and comparability across industries. An analysis of the distribution of the historical leverage ratios of large financial institutions was used to identify the 15 to 1 threshold. Historical testing of this threshold demonstrated that it would have captured the major nonbank financial companies that encountered material financial distress and posed a threat to U.S. financial stability during the recent financial crisis, including Bear Stearns, Countrywide, IndyMac Bancorp, and Lehman Brothers.

• *Short-Term Debt Ratio.* The Council intends to apply a threshold ratio of debt with a maturity of less than 12 months to total consolidated assets (excluding separate accounts) of 10 percent. An analysis of the historical distribution of the short-term debt ratios of large financial institutions was used to determine the 10 percent threshold. Historical testing of this threshold demonstrated that it would have captured a number of the nonbank financial companies that faced short-term funding issues during the recent financial crisis, including Bear Stearns and Lehman Brothers.

In addition, because the uniform quantitative thresholds may not capture all of the potential ways in which a nonbank financial company could pose a threat to financial stability, the Council may, in limited cases, initially evaluate nonbank financial companies in Stage 1 based on other firm-specific qualitative or quantitative factors, such as substitutability and existing regulatory scrutiny.

A nonbank financial company that is identified for further evaluation in Stage 1 would be further assessed during Stage 2 (the ''Stage 2 Pool'').

b. Stage 2: Review and Prioritization of Stage 2 Pool

After the Stage 2 Pool has been identified, the Council intends to conduct a robust analysis of the potential threat that each of those nonbank financial companies could pose to U.S. financial stability. In general, this analysis will be based on information already available to the Council through existing public and regulatory sources, including information possessed by the company's primary financial regulatory agency or home country supervisor, as appropriate, and information obtained from the company voluntarily. In contrast to the application of uniform quantitative thresholds to a broad group of nonbank financial companies in Stage 1, the Council intends to evaluate the risk profile and characteristics of each individual nonbank financial company in the Stage 2 Pool based on a wide range of quantitative and qualitative industry-specific and company-specific factors. This analysis will use the six-category analytic framework described in section II.d above. In addition, the Stage 2 evaluation will include a review, based on available data, of qualitative factors, including whether the resolution of a nonbank financial company, as described below, could pose a threat to U.S. financial stability, and the extent to which the nonbank financial company is subject to regulation.

Based on this analysis, the Council intends to contact those nonbank financial companies that the Council believes merit further evaluation in Stage 3 (the ''Stage 3 Pool'').

c. Stage 3: Review of Stage 3 Pool

In Stage 3, the Council, working with the OFR, will conduct a review of each nonbank financial company in the Stage 3 Pool using information collected directly from the nonbank financial company, as well as the information used in the first two stages. The review will focus on whether the nonbank financial company could pose a threat to U.S. financial stability because of the company's material financial distress or the nature, scope, size, scale, concentration, interconnectedness, or mix of the company's activities. The transmission channels discussed above, and other appropriate factors, will be used to evaluate a nonbank financial company's potential to pose a threat to U.S. financial stability. The analytic framework consisting of the six categories set forth above, and the metrics used to measure each of the six categories, will assist the Council in assessing the extent to which the transmission of material financial distress is likely to occur.

Each nonbank financial company in the Stage 3 Pool will receive a notice (a ''Notice of Consideration'') that the nonbank financial company is under consideration for a Proposed Determination. The Notice of Consideration likely will include a request that the nonbank financial company provide information that the Council deems relevant to the Council's evaluation, and the nonbank financial company will be provided an opportunity to submit written materials to the Council.[13] This information will be collected by the OFR or the appropriate regulatory agency.[14] Before requiring the submission of reports from any nonbank financial company that is regulated by a Council member agency or any primary financial regulatory agency, the Council, acting through the OFR, will coordinate with such agencies and will, whenever possible, rely on information available from the OFR or such agencies. The Council and its member agencies will maintain the confidentiality of such information to the fullest extent of applicable law.

Information requests likely will involve both qualitative and quantitative data. Information relevant to the Council's analysis may include confidential business information such as internal assessments, internal risk management procedures, funding details, counterparty exposure or position data, strategic plans, resolvability, potential acquisitions or dispositions, and other anticipated changes to the nonbank financial company's business or structure that could affect the threat to U.S. financial stability posed by the nonbank financial company.

In evaluating qualitative factors during Stage 3, the Council expects to have access, to a greater degree than during earlier stages of review, to information relating to factors that are not easily quantifiable or that may not directly cause a company to pose a threat to financial stability, but could mitigate or aggravate the potential of a nonbank financial company to pose a threat to the United States. Such factors may include the nonbank financial company's resolvability, the opacity of its operations, its complexity, and the extent to which it is subject to existing regulatory scrutiny and the nature of such scrutiny.

The Stage 3 analysis will also include an evaluation of a nonbank financial company's resolvability. An evaluation of a nonbank financial company's resolvability entails an assessment of the complexity of the nonbank financial company's legal, funding, and operational structure, and any obstacles to the rapid and orderly resolution of a nonbank financial company in a manner that would mitigate the risk that the nonbank financial company's failure would have a material adverse effect on financial stability. In addition to the factors described above, a nonbank financial company's resolvability is also a function of legal entity and cross-border operations issues. These factors include the ability to separate functions and spin off services or business lines, the likelihood of preserving franchise value in a recovery or resolution scenario, maintaining continuity of critical services within the existing or in a new legal entity or structure, the degree of the nonbank financial company's intra-group dependency for liquidity and funding, payment operation and risk management needs, and the size and nature of the nonbank financial company's intra-group transactions.

The Council anticipates that the information necessary to conduct an in-depth analysis of a particular nonbank financial company may vary significantly based on the nonbank financial company's business and activities and the information already available to the Council from existing public sources and domestic or foreign regulatory authorities. The Council will also consult with the primary financial regulatory agency, if any, for each nonbank financial company under consideration in a timely manner before the Council makes any final determination with respect to such nonbank financial company, and with appropriate foreign regulatory authorities, to the extent appropriate.

Before making a Proposed Determination, the Council intends to notify each nonbank financial company in the Stage 3 Pool when the Council believes that the evidentiary record regarding such nonbank financial company is complete.

Based on the analysis performed in Stages 2 and 3, a nonbank financial company will

[13] *See* section 1310.21(a) of the proposed rule.

[14] Under section 112(d) of the Dodd-Frank Act, if the Council is unable to determine whether a U.S. nonbank financial company poses a threat to U.S. financial stability based on such information, the Council may request that the Board of Governors conduct an examination of the nonbank financial company to determine whether it should be supervised by the Board of Governors.

be considered for a Proposed Determination. Before a vote of the Council with respect to a particular nonbank financial company, the Council members will review information relevant to the consideration of the nonbank financial company for a Proposed Determination. After this review, the Council may, by a vote of two-thirds of its members (including an affirmative vote of the Council Chairperson), make a Proposed Determination with respect to the nonbank financial company. Following a Proposed Determination, the Council intends to issue a written notice of the Proposed Determination to the nonbank financial company, which will include an explanation of the basis of the Proposed Determination. The Council expects to notify any nonbank financial company in the Stage 3 Pool if the nonbank financial company, either before or after a Proposed Determination of such nonbank financial company, ceases to be considered for determination. Any nonbank financial company that ceases to be considered at any time in the Council's determination process may be considered for Proposed Determination in the future at the Council's discretion.

A nonbank financial company that is subject to a Proposed Determination may request a hearing to contest the Proposed Determination in accordance with section 113(e) of the Dodd-Frank Act. If the nonbank financial company requests a hearing in accordance with the procedures set forth in section 1310.21(c) of the proposed rule, the Council will set a time and place for such hearing. The Council will (after a hearing, if a hearing is requested), determine by a vote of two-thirds of the voting members of the Council (including the affirmative vote of the Chairperson) whether to subject such company to supervision by the Board of Governors and prudential standards. The Council will provide the nonbank financial company with written notice of the Council's final determination, including an explanation of the basis for the Council's decision. In accordance with section 113(h) of the Dodd-Frank Act, a nonbank financial company that is subject to a final determination may bring an action in U.S. district court for an order requiring that the determination be rescinded.

Dated: October 11, 2011.

Alastair Fitzpayne,

Executive Secretary, Department of the Treasury.

[FR Doc. 2011–26783 Filed 10–17–11; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2007–28059; Directorate Identifier 2007–NE–13–AD]

RIN 2120–AA64

Airworthiness Directives; Rolls-Royce plc (RR) Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to supersede an existing airworthiness directive (AD) that applies to all RR RB211–Trent 553–61, 553A2–61, 556–61, 556A2–61, 556B–61, 556B2–61, 560–61, 560A2–61, 768–60, 772–60, 772B–60, 875–17, 877–17, 884–17, 884B–17, 892–17, 892B–17, and 895–17 turbofan engines. The existing AD currently requires inspecting the intermediate-pressure (IP) compressor rotor shaft rear balance land for cracks. Since we issued that AD, we received reports of one RB211–Trent 700 and two additional RB211–Trent 800 IP compressor rotor shafts that have been found cracked. This proposed AD would continue to require initial inspections, add additional inspections, and an optional terminating action. The cracking identified above could lead to IP compressor rotor shaft failure, uncontained engine failure, and damage to the airplane. We are proposing this AD to correct the unsafe condition on these products.

DATES: We must receive comments on this proposed AD by December 2, 2011.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this AD, contact Rolls-Royce plc, Corporate Communications, P.O. Box 31, Derby, England, DE248BJ; phone: 011–44–1332–242424; fax: 011–44–1332–245418 or e-mail from *http://www.rolls-royce.com/contact/civil_team.jsp.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803. For information on the availability of this material at the FAA, call 781–238–7125.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA; phone: 781–238–7143; fax: 781–238–7199; e-mail: *alan.strom@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2007–28059; Directorate Identifier 2007–NE–13–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

On August 25, 2008, we issued AD 2008–18–08, Amendment 39–15665 (73 FR 52201, September 9, 2008), for all Rolls-Royce plc RB211–Trent 553–61, 553A2–61, 556–61, 556A2–61, 556B–61, 556B2–61, 560–61, 560A2–61, 768–60, 772–60, 772B–60, 875–17, 877–17, 884–17, 884B–17, 892–17, 892B–17, and 895–17 turbofan engines. That AD requires a onetime eddy current inspection (ECI) of the rear balance land of the IP compressor rotor shaft for cracks. That AD resulted from reports of

cracking on the rear balance land of IP compressor rotor shafts. We issued that AD to detect cracking on the rear balance land of the IP compressor rotor shaft. Cracking on the rear balance land on the IP compressor rotor shaft can lead to failure of the rotor shaft and damage to the engine.

Actions Since Existing AD Was Issued

Since we issued AD 2008–18–08, (73 FR 52201, September 9, 2008), RR reports that they have introduced an optional terminating action to the repetitive inspections required by that AD. RR also reported that for those operators not adopting the optional terminating action, improved inspection methods for the RB211–Trent 700 and RB211–Trent 800 turbofan engines are necessary. Also, EASA issued AD 2010–0266, dated December 21, 2010, and AD 2010–0266R1, dated January 6, 2011, to require repetitive on-wing and in-shop ECIs on RB211–Trent 700 and RB211–Trent 800 engines and repetitive in-shop visual inspections on the RB211–Trent 500, RB211–Trent 700, and RB211–Trent 800 engines. EASA issued their ADs because RR had reported finding additional cracks on the IP compressor rotor shaft of two in-service RB211–Trent 800 engines and on one in-service RB211–Trent 700 engine. The cracking had initiated from frettage marks caused by balance weights. RR reports that stress analysis has shown that the cracking presents a possible threat to the rotor integrity. We evaluated the data supplied by EASA and RR, and concur that the improved inspections for cracks on the balance land of the IP compressor rotor shaft are required. We have evaluated the optional terminating action and determined it to be effective.

These cracks, if present, could result in an unsafe condition leading to IP compressor rotor shaft failure and damage to the engine.

Relevant Service Information

We reviewed RR Alert Service Bulletins (ASB) No. RB.211–72–AF260, Revision 5, dated July 7, 2011, ASB No. RB.211–72–AG085, Revision 2, dated July 7, 2011, ASB No. RB.211–72–AG264, Revision 5, dated March 21, 2011, ASB No. RB.211–72–AG270, Revision 4, dated March 21, 2011, and Service Bulletin No. RB.211–72–G448, Revision 3, dated July 7, 2011 which provide information for the inspections required by this AD.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of these same type designs.

Proposed AD Requirements

This proposed AD would require:

- For the RB211–Trent 700 and RB211–Trent 800 engines, on wing initial and repetitive borescope inspections and when in the shop, repetitive ECIs for cracks on the rear balance land; and
- For the RB211–Trent 500 engines, initial and repetitive in-shop visual inspections or ECIs for cracks on the rear balance land.

This proposed AD would also add an optional terminating action to the repetitive inspection requirements for the RB211–Trent 700 and RB211–Trent 800 engines.

Costs of Compliance

We estimate that this proposed AD would affect about 136 engines installed on airplanes of U.S. registry. We also estimate that it would take about 6 work-hours per engine to perform the proposed inspections and that the average labor rate is $85 per work-hour. Based on these figures, we estimate the total cost of the proposed AD to U.S. operators to be $69,360.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, Section 106, describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701, ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We have determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify that the proposed regulation:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska, and

(4) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by removing airworthiness directive (AD) 2008–18–08, Amendment 39–15665 (73 FR 52201, September 9, 2008), and adding the following new AD:

Rolls-Royce plc: Docket No. FAA–2007–28059; Directorate Identifier 2007–NE–13–AD.

(a) Comments Due Date

The FAA must receive comments on this AD action by December 2, 2011.

(b) Affected ADs

This AD supersedes AD 2008–18–08, Amendment 39–15665, (73 FR 52201, September 9, 2008).

(c) Applicability

This AD applies to Rolls-Royce plc (RR) RB211–Trent 553–61, 553A2–61, 556–61, 556A2–61, 556B–61, 556B2–61, 560–61, 560A2–61, 768–60, 772–60, 772B–60, 875–17, 877–17, 884–17, 884B–17, 892–17, 892B–17, and 895–17 turbofan engines.

(d) Unsafe Condition

We are superseding AD 2008–18–08 because additional cracking on RB211–Trent 700 and RB211–Trent 800 intermediate-pressure (IP) compressor rotor shafts has been found since that AD was issued. This cracking could lead to IP compressor rotor shaft failure, uncontained engine failure, and damage to the airplane.

(e) Compliance

Comply with this AD within the compliance times specified, unless already done.

(f) RB211-Trent 700 Series Engines—Rear Balance Land Inspections

(1) On-Wing Inspections

Perform on-wing inspections as follows:

(i) Within 625 cycles-in-service (CIS) after the effective date of this AD, borescope inspect the IP compressor rotor shaft rear balance land. Use RR Alert Service Bulletin (ASB) No. RB.211–72–AG270, Revision 4, dated March 21, 2011, sections 3.A.(2)(a) through 3.A.(2)(c) and 3.A.(3)(a) through 3.A.(3)(c), or 3.B.(2)(a) through 3.B.(2)(c) and 3.B.(4)(a) through 3.B.(4)(c), to do the inspection.

(ii) Thereafter, repeat the inspection within every 625 cycles-since-last inspection (CSLI). You may count CSLI from the last borescope inspection or the last eddy current inspection, whichever has occurred last.

(2) In-Shop Inspections

At each shop visit, eddy current inspect (ECI) and visually inspect the IP compressor rotor shaft rear balance land, and visually inspect the balance weights. Use RR ASB No. RB.211–72–AG085, Revision 2, dated July 7, 2011, sections 3.A. through 3.D.(3)(b)(v), except paragraphs 3.D.(3)(a)(ii) and 3.D.(3)(b)(iii) to do the inspections.

(3) RB211-Trent 800 Series Engines—Rear Balance Land Inspections

(1) On-Wing Inspections

(i) Within 475 CIS after the effective date of this AD, borescope inspect the IP compressor rotor shaft rear balance land. Use RR ASB No. RB.211–72–AG264, Revision 5, dated March 21, 2011, sections 3.B.(2)(a) through 3.B.(2)(c) and 3.B.(4)(a) through 3.B.(4)(c) to do the inspection.

(ii) Thereafter, repeat the inspection within every 475 CSLI. You may count CSLI from the last borescope inspection or the last eddy current inspection, whichever has occurred last.

(2) In-Shop Inspections

At each shop visit, ECI and visually inspect the IP compressor rotor rear shaft balance land, and visually inspect the balance weights. Use RR ASB No. RB.211–72–AG085, Revision 2, dated July 7, 2011, sections 3.A. through 3.D.(3)(b)(v), except paragraphs 3.D.(3)(a)(ii) and 3.D.(3)(b)(iii), to do the inspections.

(h) RB211-Trent 500 Series Engines—In-Shop Rear Balance Land Inspections

At each shop visit, ECI the IP compressor rotor shaft and visually inspect the balance weights. Use RR ASB No. RB.211–72–AF260, Revision 5, dated July 7, 2011 sections 3.A. through 3.B.(3)(a)(iii) to do the visual inspection, or RR SB No. RB.211–72–G448, Revision 3, dated July 7, 2011 section 3.D.(1) through 3.D.(14) to do the ECI.

(i) Definition

For the purposes of this AD, a shop visit is defined as introduction of an engine into a shop, and disassembly sufficient to expose the IP compressor module rear face.

(j) Optional Terminating Action for RB211-Trent 700 and RB211-Trent 800 Engines

(1) Modifying an RB211-Trent 700 engine as specified in RR SB No. RB.211–72–G402, Revision 2, dated July 7, 2011, or RR SB No. RB.211–72–G402, Revision 1, dated January 11, 2011, is terminating action for paragraph (f)(2) of this AD.

(2) Modifying an RB211-Trent 800 engine as specified in RR SB No. RB.211–72–G401, Revision 2, dated July 5, 2011, or SB No. RB.211–72–G401, Revision 1, dated January 11, 2011, is terminating action for paragraph (h)(2) of this AD.

(k) Previous Credit

(1) For RB211-Trent 700 series engines:

(i) On-wing inspections done before the effective date of this AD using RR ASB No. RB.211–72–AG270, Revision 1, dated December 14, 2009, or Revision 2, dated December 21, 2010, or Revision 3, dated February 25, 2011, meet the inspection requirements in paragraph (f) of this AD.

(ii) In-shop inspections done before the effective date of this AD using RR ASB No. RB.211–72–AG085, Revision 1, dated September 27, 2010, meet the inspection requirements in paragraph (g) of this AD.

(2) For RB211-Trent 800 series engines:

(i) On-wing inspections done before the effective date of this AD using RR ASB No. RB.211–72–AG264, Revision 3, dated December 21, 2010, or Revision 4, dated February 25, 2011, meet the inspection requirements in paragraph (h) of this AD.

(ii) In-shop inspections done before the effective date of this AD using RR ASB No. RB.211–72–AG085, Revision 1, dated September 27, 2010, meet the inspection requirements in paragraph (i) of this AD.

(3) For RB211-Trent 500 series engines:

(i) In-shop visual inspections done before the effective date of this AD using RR ASB No. RB.211–72–AF260, Revision 4, dated July 28, 2009, meet the inspection requirements in paragraph (j) of this AD.

(ii) In-shop ECIs done before the effective date of this AD using RR ASB No. RB.211–72–G448, Revision 2, dated December 23, 2010, meet the ECI requirements in paragraph (j) of this AD.

(l) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, may approve AMOCs for this AD. Use the procedures in 14 CFR 39.19 to request an AMOC.

(m) Related Information

(1) For more information about this AD, contact Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA; phone: 781–238–7143; fax: 781–238–7199; e-mail: *alan.strom@faa.gov.*

(2) For service information identified in this AD, contact Rolls-Royce plc, Corporate Communications, P.O. Box 31, Derby, England, DE248BJ; phone: 011–44–1332–242424; fax: 011–44–1332–245418; or e-mail from *http://www.rolls-royce.com/contact/civil_team.jsp.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803. For information on the availability of this material at the FAA, call 781–238–7125.

Issued in Burlington, Massachusetts, on October 6, 2011.

Peter A. White,

Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26821 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2009–0948; Directorate Identifier 2009–NE–30–AD]

RIN 2120–AA64

Airworthiness Directives; Thielert Aircraft Engines GmbH (TAE) Models TAE 125–02–99 and TAE 125–01 Reciprocating Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to revise an existing airworthiness directive (AD) for the products listed above. This proposed AD results from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product and from a comment received from the European Aviation Safety Agency (EASA) on AD 2010–06–12, (75 FR 12439, March 16, 2010). The MCAI describes the unsafe condition as:

As a consequence of occurrences and service experience, Thielert Aircraft Engines GmbH has introduced a new rail pressure control valve part number (P/N) 05–7320–E000702 and has amended the Airworthiness Limitation Section (ALS) of the Operation & Maintenance Manual OM–02–02 to include a replacement of the rail pressure control valve. Failure of this part could result in in-flight shutdowns of the engine(s).

TAE has also amended the ALS of the Operation & Maintenance Manual OM–02–01 to include a replacement of the rail pressure valve. We are proposing this AD to prevent engine in-flight shutdown, possibly resulting in reduced control of the aircraft.

DATES: We must receive comments on this proposed AD by November 17, 2011.

ADDRESSES: You may send comments by any of the following methods:

• *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.

• *Mail:* Docket Management Facility, U.S. Department of Transportation, 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.

• *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

• *Fax:* (202) 493–2251.

Contact Thielert Aircraft Engines GmbH, Platanenstrasse 14 D–09350, Lichtenstein, Germany, phone: +49–37204–696–0; fax: +49–37204–696–55; e-mail: *info@centurion-engines.com* for the service information identified in this proposed AD.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (phone: 800–647–5527) is the same as the Mail address provided in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, Engine and Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7143; fax: 781–238–7199; e-mail: *alan.strom@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2009–0948; Directorate Identifier 2009–NE–30–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of the Web site, anyone can find and read the comments in any of our dockets, including, if provided, the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78).

Discussion

On March 8, 2010, the FAA issued AD 2010–06–12, (75 FR 12439, March 16, 2010). That AD requires initial and repetitive replacements of the rail pressure control valve.

Actions Since AD 2010–06–12 Was Issued

Since we issued AD 2010–06–12, (75 FR 12439, March 16, 2010), EASA, which is the Technical Agent for the Member States of the European Community, informed us that our AD is more restrictive than their EASA AD 2008–0128, dated July 9, 2009. Specifically, our paragraph (e)(3), which currently states:

''For TAE 125–01 reciprocating engines, within 100 flight hours after the effective date of this AD, replace the existing rail pressure control valve with a rail pressure control valve, P/N 02–7320–04100R3'' should state:

''For TAE 125–01 reciprocating engines, before 600 flight hours time-since-new, or within 100 flight hours after the effective date of this AD, whichever occurs later, replace the existing rail pressure control valve with a rail pressure control valve, P/N 02–7320–04100R3.''

We agree. We made the suggested change in this proposed AD. We also deleted the AD Differences paragraph (f)(2), which stated: ''For the TAE 125–01 reciprocating engines, we changed initial compliance time from within the next 3 months to within 100 flight hours after the effective date of this AD.'' The remainder of this proposed AD is unchanged.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of Germany and is approved for operation in the United States. Pursuant to our bilateral agreement with the European Community, EASA has notified us of the unsafe condition described in the MCAI. We are proposing this AD because we evaluated all information provided by EASA and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design. This proposed AD would require initial and repetitive replacements of the rail pressure control valve.

Differences Between This Proposed AD and the MCAIs or Service Information

We have reviewed the MCAIs and related service information and, in general, agree with their substance. But we have found it necessary to reduce the initial compliance time for TAE 125–02–99 engines from within 110 flight hours to within 100 flight hours. We also have found it necessary to specify the repetitive replacement compliance time for the rail pressure control valve of within every 600 flight hours for both models of engines. The MCAIs instruct the operators to follow Thielert Maintenance Manual, Chapter 5, Airworthiness Limitations, for the repetitive compliance time, which requires replacement of the rail pressure control valve within every 600 flight hours. In making these changes, we do not intend to differ substantively from the information provided in the MCAI and related service information.

Costs of Compliance

Based on the service information, we estimate that this proposed AD would affect about 370 TAE 125–01 and TAE 125–02–99 reciprocating engines installed on products of U.S. registry. We also estimate that it would take about 1.5 work-hours per engine to comply with this proposed AD. The average labor rate is $85 per work-hour. Required parts would cost about $500 per engine. Based on these figures, we estimate the cost of the proposed AD for initial replacement, on U.S. operators to be $232,175.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on

products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by removing Amendment 39–16236, and adding the following new AD:

Thielert Aircraft Engines GmbH: Docket No. FAA–2009–0948; Directorate Identifier 2009–NE–30–AD.

Comments Due Date

(a) We must receive comments by November 17, 2011.

Affected Airworthiness Directives (ADs)

(b) This AD revises AD 2010–06–12, Amendment 39–16236.

Applicability

(c) This AD applies to Thielert Aircraft Engines GmbH (TAE) models TAE 125–01 and TAE 125–02–99 reciprocating engines installed in, but not limited to, Cessna 172 and (Reims-built) F172 series (European Aviation Safety Agency (EASA) Supplemental Type Certificate (STC) No. EASA.A.S.01527); Piper PA–28 series (EASA STC No. EASA.A.S. 01632); APEX (Robin) DR 400 series (EASA STC No. A.S.01380); and Diamond Aircraft Industries Models DA40 and DA42 airplanes.

Reason

(d) As a consequence of occurrences and service experience, Thielert Aircraft Engines GmbH has introduced a new rail pressure control valve part number (P/N) 05–7320–E000702 and has amended the Airworthiness Limitation Section (ALS) of the Operation & Maintenance Manual OM–02–02 to include a replacement of the rail pressure control valve. Failure of this part could result in in-flight shutdowns of the engine(s).

TAE has also amended the ALS of the Operation & Maintenance Manual OM–02–01 to include a replacement of the rail pressure valve. This AD results from mandatory continuing airworthiness information (MCAIs) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product and from a comment received from EASA on AD 2010–06–12. We are issuing this AD to prevent engine in-flight shutdown, possibly resulting in reduced control of the aircraft.

Actions and Compliance

(e) Unless already done, do the following actions.

TAE 125–02–99 Reciprocating Engines

(1) For TAE 125–02–99 reciprocating engines, within 100 flight hours after the effective date of this AD, replace the existing rail pressure control valve with a rail pressure control valve P/N 05–7320–E000702, and modify the Vrail plug to make it compatible with the replacement rail pressure control valve.

(2) Guidance on the valve replacement and rail modification specified in paragraph (e)(1) of this AD can be found in Thielert Repair Manual RM–02–02, Chapter 73–10.08, and Chapter 39–40.08, respectively.

TAE 125–01 Reciprocating Engines

(3) For TAE 125–01 reciprocating engines, before 600 flight hours time-since-new, or within 100 flight hours after the effective date of this AD, whichever occurs later, replace the existing rail pressure control valve with a rail pressure control valve, P/N 02–7320–04100R3.

(4) Guidance on the valve replacement specified in paragraph (e)(3) of this AD can be found in Thielert Repair Manual RM–02–01, Chapter 29.0.

TAE 125–02–99 and TAE 125–01 Engines, Repetitive Replacements of Rail Pressure Control Valves

(5) Thereafter, for affected TAE 125–02–99 and TAE 125–01 engines, replace the rail pressure control valve with the same P/N valve within every 600 flight hours.

FAA AD Differences

(f) This AD differs from the Mandatory Continuing Airworthiness Information (MCAI) and/or service information as follows:

(1) For the TAE 125–02–99 reciprocating engines, we reduced the initial compliance time from within 110 flight hours to within 100 flight hours after the effective date of this AD.

(2) The MCAIs instruct the operators to follow Thielert Maintenance Manual, Chapter 5, Airworthiness Limitations, for the repetitive compliance time for the rail pressure control valve, which, in the manual, is 600 flight hours. We found it necessary to specify the repetitive replacement compliance time in this AD, to within every 600 flight hours.

Alternative Methods of Compliance (AMOCs)

(g) The Manager, Engine Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

Related Information

(h) Refer to MCAI EASA AD 2008–0128, dated July 9, 2008, EASA AD 2008–0215, dated December 5, 2008, Thielert Service Bulletin No. TAE 125–1008 P1, Revision 1, dated September 29, 2008, and Thielert Repair Manual RM–02–02, for related information. Contact Thielert Aircraft Engines GmbH, Platanenstrasse 14 D–09350, Lichtenstein, Germany, telephone: +49–37204–696–0; fax: +49–37204–696–55; e-mail: *info@centurion-engines.com,* for a copy of this service information.

(i) Contact Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, Engine and Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; telephone 781–238–7143; fax 781–238–7199; e-mail: *alan.strom@faa.gov,* for more information about this AD.

Issued in Burlington, Massachusetts, on October 6, 2011.

Peter A. White,

Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26822 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2011–0599; Directorate Identifier 2011–NE–19–AD]

RIN 2120–AA64

Airworthiness Directives; General Electric Company CF34–10E Series Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for General Electric Company (GE) CF34–10E series turbofan engines. This proposed AD was

prompted by a report of heavy wear found on the seating surface of the center vent duct (CVD) (commonly referred to as center vent tube) support ring and on the inside diameter of the fan drive shaft at the mating location. This proposed AD would require removing from service CVD support assemblies from certain serial numbers (S/Ns) of CF34–10E series turbofan engines. This proposed AD would also require removing any fan drive shaft from service if wear is found on either the CVD support ring or the fan drive shaft. We are proposing this AD to prevent fan drive shaft failure, leading to uncontained engine failure and damage to the airplane.

DATES: We must receive comments on this proposed AD by December 2, 2011.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this AD, contact GE-Aviation, M/D Rm. 285, One Neumann Way, Cincinnati, OH 45215, phone: 513–552–3272; e-mail: *geae.aoc@ge.com.* Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: John Frost, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7756; fax: 781–238–7199; e-mail: *john.frost@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2011–0599; Directorate Identifier 2011–NE–19–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

We received a report of wear found on the seating surface of the CVD support ring and on the inside diameter of the fan drive shaft, where the two parts are in contact with each other. The wear was caused by relative motion between the CVD support assembly and the fan drive shaft during engine operation. The relative motion resulted from CVD support assemblies with improper sleeve thread lengths. This nonconformance was caused during manufacture, and the affected parts were released into service. A subpopulation of engines has been identified by engine S/N, that could have the same quality escape. Once removed, the CVD support assembly (consisting of self-locking nut, part number (P/N) 2226M57G03, threaded sleeve, P/N 2226M55P03, and support ring, P/N 2226M56P01) will be inspected for evidence of wear, and then never used again. This condition, if not corrected, could result in low-cycle-fatigue failure of the fan drive shaft, leading to engine failure.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the condition described previously is unsafe and is likely to exist or develop in other products of the same type design.

Proposed AD Requirements

This proposed AD would require:

- First inspecting the seating surface of the CVD support ring for wear, and then inspecting the fan drive shaft inside diameter for wear, where the two parts come in contact with each other;
- If wear is found on either the CVD support ring seating surface or the corresponding contact area inside the fan drive shaft, then removing the fan drive shaft from service; and
- Removing from service all of the CVD support assemblies from the affected S/N engines identified in the proposed AD.

Costs of Compliance

We estimate that this proposed AD would affect 71 GE CF34–10E series turbofan engines installed on airplanes of U.S. registry. We also estimate that it would take about 8 work-hours per engine to perform a replacement of the CVD support assembly and visual inspections, and that the average labor rate is $85 per work-hour. A replacement CVD support assembly costs about $3,080. We estimate that two fan drive shafts would fail inspection and require replacement. A replacement fan drive shaft costs about $126,900. We estimate that no additional labor costs would be incurred to perform the required part replacements as the replacements are done at time of scheduled engine shop visit. Based on these figures, we estimate the total cost of the AD to U.S. operators to be $520,760.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the

distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska, and

(4) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

General Electric Company: Docket No. FAA–2011–0599; Directorate Identifier 2011–NE–19–AD.

(a) Comments Due Date

We must receive comments by December 2, 2011.

(b) Affected ADs

None.

(c) Applicability

This AD applies to General Electric Company (GE) CF34–10E series turbofan engines, serial number (S/N) 994116, and S/Ns 994118 through 994186 inclusive.

(d) Unsafe Condition

This AD was prompted by a report of heavy wear found on the seating surface of the center vent duct (CVD) (commonly referred to as center vent tube) support ring and on the inside diameter of the fan drive shaft at the mating location. The wear is caused by relative motion between the CVD support assembly (consisting of self-locking nut, part number (P/N) 2226M57G03, threaded sleeve, P/N 2226M55P03, and support ring, P/N 2226M56P01) and the fan drive shaft, during engine operation. We are issuing this AD to prevent fan drive shaft failure, leading to uncontained engine failure and damage to the airplane.

(e) Compliance

Comply with this AD before accumulating 11,500 total cycles-in-service on the engine, unless already done.

(f) Inspection and Removal From Service of CVD Support Assembly; and Determination of Fan Drive Shaft Serviceability

Visually inspect the seating surface of the CVD support ring for wear.

(1) If there is sign of wear on the CVD support ring, remove the CVD support assembly and the fan drive shaft from service before further flight.

(2) If there is no sign of wear on the CVD support ring, remove the CVD support assembly from service and borescope inspect the inside diameter of the fan drive shaft at the CVD support ring contact area, for wear.

(3) If there is sign of wear on the fan drive shaft, remove the fan drive shaft from service before further flight.

(g) Installation Prohibition

After the effective date of this AD, do not return to service any CVD support assembly (consisting of self-locking nut, P/N 2226M57G03, threaded sleeve, P/N 2226M55P03, and support ring, P/N 2226M56P01) removed from service as specified in this AD.

(h) Definition

For the purposes of this AD, the phrase ''any sign of wear'' is defined as any visual indication of removal of parent material from the CVD seating surface or the fan drive shaft.

(i) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

(j) Related Information

(1) For more information about this AD, contact John Frost, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7756; fax: 781–238–7199; e-mail: *john.frost@faa.gov.*

(2) Refer to GE Service Bulletin No. CF34–10E S/B 72–0188, for related information. Contact GE–Aviation, M/D Rm. 285, One Neumann Way, Cincinnati, OH 45215, phone: 513–552–3272; e-mail: *geae.aoc@ge.com,* for a copy of this service information. You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

Issued in Burlington, Massachusetts, on October 6, 2011.

Peter A. White,

Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26824 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2011–0956; Directorate Identifier 2011–NE–23–AD]

RIN 2120–AA64

Airworthiness Directives; Thielert Aircraft Engines GmbH (TAE) TAE 125–02–99 and TAE 125–02–114 Reciprocating Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for the products listed above. This proposed AD results from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

In-flight engine shutdown incidents have been reported on aeroplanes equipped with TAE 125 engines. Preliminary investigations showed that it was mainly the result of the sensitivity of friction disk Part Number (P/N) 05–7211–K010201 against possible misalignment of gearbox and core engine during assembly.

This condition, if not corrected, could result in further cases of engine in-flight shutdown and consequent loss of control of the aeroplane.

To address this unsafe condition, Thielert Aircraft Engines GmbH has developed a new friction disk.

We are proposing this AD to prevent in-flight engine shutdown, which could result in loss of control of the airplane.

DATES: We must receive comments on this proposed AD by December 2, 2011.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* Docket Management Facility, U.S. Department of Transportation, 1200 New Jersey Avenue, SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Fax:* 202–493–2251.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://*

www.regulations.gov; or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (phone: 800–647–5527) is the same as the Mail address provided in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA; phone: 781–238–7143; fax: 781–238–7199; e-mail: *alan.strom@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2011–0956; Directorate Identifier 2011–NE–23–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this proposed AD. Using the search function of the Web site, anyone can find and read the comments in any of our dockets, including, if provided, the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, *etc.*). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78).

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Community, has issued EASA AD 2011–0087–E, dated May 12, 2011 (referred to after this as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> In-flight engine shutdown incidents have been reported on aeroplanes equipped with TAE 125 engines.
>
> Preliminary investigations showed that it was mainly the result of the sensitivity of friction disk Part Number (P/N) 05–7211–K010201 against possible misalignment of gearbox and core engine during assembly.
>
> This condition, if not corrected, could result in further cases of engine in-flight shutdown and consequent loss of control of the aeroplane.
>
> To address this unsafe condition, Thielert Aircraft Engines GmbH has developed a new friction disk.

We are proposing this AD to require replacement of affected friction disks, which would resolve the unsafe condition described above. You may obtain further information by examining the MCAI in the AD docket.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of Germany, and is approved for operation in the United States. Pursuant to our bilateral agreement with the European Community, EASA notified us of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all information provided by EASA and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design. This proposed AD would require on all TAE 125–02–99 and TAE 125–02–114 reciprocating engines, replacing the friction disk, P/N 05–7211–K010201.

Costs of Compliance

Based on the service information, we estimate that this proposed AD would affect about 206 TAE 125–02–99 and TAE 125–02–114 reciprocating engines installed on airplanes of U.S. registry. We also estimate that it would take about 3 work-hours per engine to comply with this proposed AD. The average labor rate is $85 per work-hour. Required parts would cost about $1,500 per engine. Based on these figures, we estimate the cost of the proposed AD on U.S. operators to be $361,530. Our cost estimate is exclusive of possible warranty coverage.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. ''Subtitle VII: Aviation Programs,'' describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in ''Subtitle VII, Part A, Subpart III, Section 44701: General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and

3. Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

We prepared a regulatory evaluation of the estimated costs to comply with this proposed AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

Thielert Aircraft Engines GmbH: Docket No. FAA–2011–0956; Directorate Identifier 2011–NE–23–AD.

(a) Comments Due Date

We must receive comments by December 2, 2011.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Thielert Aircraft Engines GmbH TAE 125–02–99 and TAE–125–02–114 reciprocating engines with friction disk, part number (P/N) 05–7211–K010201, installed.

(d) Reason

This AD results from mandatory continuing airworthiness information (MCAI) issued by an aviation authority of another country to identify and correct an unsafe condition on an aviation product. The MCAI describes the unsafe condition as:

In-flight engine shutdown incidents have been reported on aeroplanes equipped with TAE 125 engines. Preliminary investigations showed that it was mainly the result of the sensitivity of friction disk Part Number (P/N) 05–7211–K010201 against possible misalignment of gearbox and core engine during assembly.

This condition, if not corrected, could result in further cases of engine in-flight shutdown and consequent loss of control of the aeroplane.

To address this unsafe condition, Thielert Aircraft Engines GmbH has developed a new friction disk.

We are issuing this AD to prevent in-flight engine shutdown, which could result in loss of control of the airplane.

(e) Actions and Compliance

Unless already done, do the following actions.

(1) TAE 125–02–99 Engines, P/Ns 05–7200–K000201; 05–7200–K000701; 05–7200–K000101; 05–7200–K000901; 05–7200–K001101; and 05–7200–K001301; and TAE 125–02–114 Engines, P/Ns 05–7200–K000501; 05–7200–K000801; and 05–7200–K001401

For TAE 125–02–99 engines, P/Ns 05–7200–K000201; 05–7200–K000701; 05–7200–K000101; 05–7200–K000901; 05–7200–K001101; and 05–7200–K001301; and TAE 125–02–114 engines, P/Ns 05–7200–K000501; 05–7200–K000801; and 05–7200–K001401, remove friction disk, P/N 05–7211–K010201, within 100 flight hours (FH) time-since-new (TSN) on the clutch or within 10 FH time-in-service (TIS) after the effective date of this AD, whichever is later.

(2) TAE 125–02–99 Engines, P/Ns 05–7200–K000301

For TAE 125–02–99 engines, P/N 05–7200–K000301, installed on multiengine aircraft, remove friction disk, P/N 05–7211–K010201, on one engine within 100 FH TSN on the clutch or within 10 FH TIS after the effective date of this AD, whichever is later. Remove friction disk, P/N 05–7211–K010201, from the other engine within 300 FH TSN on the clutch or within 10 FH TIS after the effective date of this AD, whichever is later.

(f) Installation Prohibition

After the effective date of this AD:

(1) Do not install any friction disk, P/N 05–7211–K010201, into any engine.

(2) Do not install any TAE 125–02–99 engine, P/N 05–7200–K000201, 05–7200–K000301, or 05–7200–K000701, or TAE 125–02–114 engine, P/N 05–7200–K00801 or 05–7200–K00501, that has a friction disk, P/N 05–7211–K010201 installed, onto any airplane.

(g) Operating Prohibition

Do not operate any multi-engine aircraft after 300 FH TSN on the clutch or 10 FH TIS after the effective date of this AD, whichever is later, which has installed a friction disk, P/N 05–7211–K010201.

(h) FAA AD Differences

The MCAI mandates the replacement friction disk P/N. This AD does not.

(i) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

(j) Related Information

(1) Refer to MCAI EASA Airworthiness Directive 2011–0087–E, dated May 12, 2011, and Thielert Service Bulletin No. TM TAE 125–1013 P1, for related information. Contact Thielert Aircraft Engines GmbH, Platanenstrasse 14 D–09350, Lichtenstein, Germany, telephone: +49–37204–696–0; fax: +49–37204–696–55; e-mail: *info@centurion-engines.com,* for a copy of this service information.

(2) Contact Alan Strom, Aerospace Engineer, Engine Certification Office, FAA, 12 New England Executive Park, Burlington, MA; phone: 781–238–7143; fax: 781–238–7199; e-mail: *alan.strom@faa.gov,* for more information about this AD.

Issued in Burlington, Massachusetts, on October 4, 2011.

Peter A. White,

Manager, Engine and Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26827 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2011–0982; Directorate Identifier 2011–NE–09–AD

RIN 2120–AA64

Airworthiness Directives; General Electric Company (GE) Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for all GE CF6–80C2A1, CF6–80C2A2, CF6–80C2A3, CF6–80C2A5, CF6–80C2A5F, CF6–80C2A8, CF6–80C2B1, CF6–80C2B1F, CF6–80C2B1F1, CF6–80C2B1F2, CF6–80C2B2, CF6–80C2B2F, CF6–80C2B3F, CF6–80C2B4, CF6–80C2B4F, CF6–80C2B5F, CF6–80C2B6, CF6–80C2B6F, CF6–80C2B6FA, CF6–80C2B7F, CF6–80C2B8F, CF6–80C2D1F, CF6–80C2K1F, and CF6–80C2L1F turbofan engines, including engines marked on the engine data plate as CF6–80C2B7F1. This proposed AD was prompted by a report of a supplier shipping a batch of nonconforming No. 3 bearing packings that had incorrect cooling holes, and by subsequent reports of nonconforming No. 3 bearing packings being installed on engines in service. This proposed AD would require a one-time inspection of the No. 3 bearing packing for an incorrect cooling hole size and, if it is found nonconforming, removing the packing and removing certain engine rotating life-limited parts, if they were operated with the wrong packing for a specified number of cycles. We are proposing this AD to prevent an uncontained failure of the high-pressure compressor (HPC) rotor or the low-pressure turbine (LPT) rotor or both, which could cause damage to the airplane.

DATES: We must receive comments on this proposed AD by December 2, 2011.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact GE-Aviation M/D Rm. 285, One Neumann Way, Cincinnati, OH 45215, telephone 513–552–3272; e-mail: *geae.aoc@ge.com.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA. For information on the availability of this material at the FAA, call 781–238–7125.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD

docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Tomasz Rakowski, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7735; fax: 781–238–7199; e-mail: *tomasz.rakowski@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2011–0982; Directorate Identifier 2011–NE–09–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

We received a report that a supplier shipped a batch of nonconforming No. 3 bearing packings, part number (P/N) 1292M70P04, with undersized cooling holes. The No. 3 bearing packing design did not feature permanent part markings and parts could be confused when being installed. After GE changed the design to introduce part marking on all new-made parts and added secondary inspections to the CF6–80C2 engine manual section 72–23–00 Fan Frame Assembly, customers reported several nonconforming No. 3 bearing packings, various P/Ns, found installed on engines in-service outside of the known population of engines affected by the quality escape. The nonconformance of No. 3 bearing packings will result in incorrect HPC and LPT rotor bore cooling and, if not corrected, could result in a reduced parts life of the life-limited HPC rotor stage 10-through-stage 14 spool, the HPC rotor stage 11-through-stage 14 spool, the LPT rotor stage 3 disk, and the LPT rotor stage 4 disk. Because the problem exists beyond the known population of engines affected by the quality escape and the consequences represent an unsafe condition in all affected engines in service, it is necessary to inspect the No. 3 bearing packing configuration of the entire fleet. This condition, if not corrected, could result in failure of the HPC rotor or the LPT rotor or both, which could cause uncontained engine failure and damage to the airplane.

Relevant Service Information

We reviewed GE Service Bulletin (SB) CF6–80C2 S/B 72–1405, dated June 30, 2011. The SB describes procedures for inspecting and removing the nonconforming No. 3 bearing packing, and determining the effect of nonconforming packing on the HPC and LPT rotor bore cooling.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements

This proposed AD would require:

- A one-time inspection of the No. 3 bearing packing at the next engine shop visit, but not later than 5,500 cycles-in-service (CIS) since the last engine shop visit where the fan was removed from the core.
- Removing the No. 3 bearing packing if it is found to be nonconforming within the above specified times.
- Removing certain rotating parts if they have operated more than 5,500 CIS with the wrong packing configuration.

Differences Between the Proposed AD and the Service Information

This proposed AD includes CF6 engine models CF6–80C2B1F1, CF6–80C2B1F2, CF6–80C2B3F, and CF6–C2B7F1 in the Applicability paragraph (c). The GE service information does not include these engine models.

Costs of Compliance

We estimate that this proposed AD would affect 688 engines installed on airplanes of U.S. registry. We also estimate that it would take about 1 work-hour per engine to perform the inspection and 1 work-hour to replace the No. 3 bearing packing, if found nonconforming. The average labor rate is $85 per work-hour. Required parts would cost about $488 per engine to replace an anticipated quantity of 21 No. 3 bearing packings. Based on these figures, we estimate the total cost of this proposed AD to U.S. operators to be $70,513. GE has informed us that they may cover these costs under warranty.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska, and

(4) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

General Electric Company (GE): Docket No. FAA–2011–0982; Directorate Identifier 2011–NE–09–AD.

(a) Comments Due Date

We must receive comments by December 2, 2011.

(b) Affected ADs

None.

(c) Applicability

This AD is applicable to all GE CF6–80C2A1, CF6–80C2A2, CF6–80C2A3, CF6–80C2A5, CF6–80C2A5F, CF6–80C2A8, CF6–80C2B1, CF6–80C2B1F, CF6–80C2B1F1, CF6–80C2B1F2, CF6–80C2B2, CF6–80C2B2F, CF6–80C2B3F, CF6–80C2B4, CF6–80C2B4F, CF6–80C2B5F, CF6–80C2B6, CF6–80C2B6F, CF6–80C2B6FA, CF6–80C2B7F, CF6–80C2B8F, CF6–80C2D1F, CF6–80C2K1F and CF6–80C2L1F turbofan engines, including engines marked on the engine data plate as CF6–80C2B7F1.

(d) Unsafe Condition

This AD was prompted by a report of a supplier shipping a batch of nonconforming No. 3 bearing packings that had an incorrect size of cooling holes and by several subsequent reports of nonconforming No. 3 bearing packings being installed on engines in service. The nonconformance of No. 3 bearing packings will result in incorrect high-pressure compressor (HPC) rotor and low-pressure turbine (LPT) rotor bore cooling and, if not corrected, could result in a reduced parts life of the life-limited rotating parts. We are issuing this AD to prevent an uncontained failure of the high-pressure compressor (HPC) rotor or the low-pressure turbine (LPT) rotor or both, which could cause damage to the airplane.

(e) Compliance

Comply with this AD within the compliance times specified, unless already done.

(f) One-Time Inspection of the No. 3 Bearing Packing and Disposition of Affected Rotating Parts

(1) Perform a one-time inspection of the No. 3 bearing packing at the next engine shop visit, but not later than 5,500 cycles-in-service (CIS) since the last engine shop visit, where the fan was removed from the core. Use paragraphs 3.A.(1) through 3.A.(1).(a) of the Accomplishment Instructions of GE Service Bulletin (SB) No. CF6–80C2 S/B 72–1405, dated June 30, 2011.

(2) If the packing part number (P/N) is determined not eligible for installation on the engine, then before further flight:

(i) Remove the nonconforming packing from service; and

(ii) Remove the following rotating parts from service, if they were operated for 5,500 CIS or more with a packing determined to be other than a ''CORRECT FLOW'' packing using paragraph 3.A.(1).(b) of the Accomplishment Instructions of SB No. CF6–80C2 S/B 72–1405, dated June 30, 2011:

(A) HPC rotor stage 10-through-14 spool, any P/N,

(B) HPC rotor stage 11-through-14 spool, any P/N,

(C) LPT rotor stage 3 disk, P/N 9373M53P05, and

(D) LPT rotor stage 4 disk, P/N 9373M54P03.

(g) Definition

For the purposes of this AD, an engine shop visit is the induction of an engine into the shop after the effective date of this AD, where the separation of a major engine flange occurs; except the following maintenance actions, or any combination, are not considered engine shop visits:

(1) Introduction of an engine into a shop solely for removal of the compressor top or bottom case for airfoil maintenance or variable stator vane bushing replacement.

(2) Introduction of an engine into a shop solely for replacement of the turbine rear frame.

(3) Introduction of an engine into a shop solely for replacement of the accessory gearbox or transfer gearbox, or both.

(h) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

(i) Related Information

(1) For more information about this AD, contact Tomasz Rakowski, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7735; fax: 781–238–7199; e-mail: *tomasz.rakowski@faa.gov.*

(2) For service information identified in this AD, contact GE-Aviation M/D Rm. 285, One Neumann Way, Cincinnati, OH 45215, phone 513–552–3272; e-mail: *geae.aoc@ge.com.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA, 01803. For information on the availability of this material at the FAA, call 781–238–7125.

Issued in Burlington, Massachusetts, on October 6, 2011.

Peter A. White,

Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26825 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2011–0946; Directorate Identifier 2011–NE–02–AD]

RIN 2120–AA64

Airworthiness Directives; CFM International, S. A. Model CFM56–5B Series Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for the products listed above. This proposed AD would require removing from service certain serial number (S/N) fan blades, part number (P/N) 338–002–114–0. This proposed AD was prompted by a normal quality sampling at CFM that isolated a production batch of fan blades with nonconforming geometry of mid-span shroud tips of the fan blades. This defect would cause the upper panel of the fan blade to be liberated following foreign object damage (FOD) or bird strike, and likely result in an inflight shutdown (IFSD). We are proposing this AD to prevent an IFSD of one or more engines following FOD or a bird strike.

DATES: We must receive comments on this proposed AD by December 2, 2011.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact CFM International, Inc., Aviation Operations Center, 1 Neumann Way, M/D Room 285, Cincinnati, OH 45125; International Phone: 1–513–552–3272; USA Phone: 877–432–3272; International Fax: 1–513–552–3329; USA Fax: 877–432–3329; e-mail: *geae.aoc@ge.com;* or CFM International SA, Customer Support Center, International Phone: 33 1 64 14 88 66; Fax: 33 1 64 79 85 55; e-mail: *snecma.csc@snecma.fr.*

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Carlos Fernandes, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7189; fax: 781–238–7199; e-mail: *carlos.fernandes@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2011–0946; Directorate Identifier 2011–NE–02–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this proposed AD.

Discussion

We received a report that CFM International conducted a normal quality sampling on fan blades, P/N 338–002–114–0, from a supplier. That quality investigation isolated a production batch of 706 blades that did not conform to the engineering drawings for the fan blades. The supplier had performed a hand-polishing operation that reduced the contact surface on adjacent blades. The reduced surface contact will likely create greater contact forces on the adjacent blades during a FOD or bird strike event. The increased forces would cause the upper panel of the fan blade to be liberated following FOD or bird strike and likely result in an IFSD.

Relevant Service Information

We reviewed CFM International Service Bulletin (SB) CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011. The SB describes procedures for replacing the suspect fan blades and contains an appendix that lists suspect fan blades, P/N 338–002–114–0, by blade S/N and known engine S/N.

FAA's Determination

We are proposing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements

This proposed AD would require removing from service within 5,000 flight hours (FHs) after the effective date of this proposed AD, any fan blade, P/N 338–002–114–0, that has an S/N listed in CFM International SB CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011. After the effective date of this proposed AD, it would also prohibit installing any fan blade, P/N 338–002–114–0, that has an S/N listed in Appendix A of CFM International SB CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011.

Differences Between the Proposed AD and the Service Information

CFM International SB CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011, requires replacing suspect fan blades within 1,600 FHs on airplanes with suspected blades on both engines and within 5,000 FHs on airplanes with suspected blades on one engine. This proposed AD would require removing from service suspect blades on any engine within 5,000 FHs based on risk analysis.

Costs of Compliance

We estimate that this proposed AD would affect 16 engines installed on airplanes of U.S. registry. We also estimate that it would take about 6 work-hours per engine to perform the required actions and that the average labor rate is $85 per work-hour. Required parts would cost about $47,830 per engine. Based on these figures, we estimate the total cost of this proposed AD to U.S. operators to be $773,440.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would not have a substantial direct effect on the States, on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this proposed regulation:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska, and

(4) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

CFM International S.A.: Docket No. FAA–2011–0946; Directorate Identifier 2011–NE–02–AD.

Comments Due Date

(a) We must receive comments by December 2, 2011.

Affected ADs

(b) None.

Applicability

(c) This AD applies to CFM International, S.A. CFM56–5B1/3, CFM56–5B2/3, CFM56–5B3/3, CFM56–5B4/3, CFM56–5B5/3, CFM56–5B6/3, CFM56–5B7/3, CFM56–5B8/3, CFM56–5B9/3, CFM56–5B3/3B1, and CFM56–5B4/3B1 engines equipped with fan blades P/N 338–002–114–0 that have a serial number (S/N) listed in Appendix A of CFM International Service Bulletin (SB) CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011.

Unsafe Condition

(d) This AD was prompted by a normal quality sampling at CFM that isolated a production batch of fan blades with nonconforming geometry of mid-span shroud tips of the fan blades. This defect would cause the upper panel of the fan blade to be liberated following foreign object damage (FOD) or a bird strike and likely result in an inflight shutdown (IFSD). We are proposing this AD to prevent an IFSD of one or more engines following FOD or a bird strike.

Compliance

(e) Comply with this AD within the compliance times specified, unless already done.

Remove Fan Blades From Service

(f) For engines that have fan blades, P/N 338–002–114–0 with S/Ns listed in Appendix A of CFM International SB CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011, remove the fan blade from service within 5,000 flight hours after the effective date of this AD.

Installation Prohibition

(g) After the effective date of this AD, do not install any fan blade, P/N 338–002–114–0 that has an S/N listed in Appendix A of CFM International SB CFM56–5B S/B 72–0777, Revision 1, dated April 11, 2011, onto any engine.

Alternative Methods of Compliance (AMOCs)

(h) The Manager, Engine Certification Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19.

Related Information

(i) For more information about this AD, contact Carlos Fernandes, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7189; fax: 781–238–7199; e-mail: *carlos.fernandes@faa.gov.*

(j) For service information identified in this AD, contact CFM International, Inc., Aviation Operations Center, 1 Neumann Way, M/D Room 285, Cincinnati, OH 45125; International Phone: 1–513–552–3272; USA Phone: 877–432–3272; International Fax: 1–513–552–3329; USA Fax: 877–432–3329; e-mail: *geae.aoc@ge.com;* or CFM International SA, Customer Support Center, International Phone: 33 1 64 14 88 66; Fax: 33 1 64 79 85 55; e-mail: *snecma.csc@snecma.fr.* You may review copies of the referenced service information at the FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA, 01803. For information on the availability of this material at the FAA, call 781–238–7125.

Issued in Burlington, Massachusetts on October 6, 2011.

Peter A. White,

Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2011–26823 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2011–1057; Airspace Docket No. 11–AEA–21]

Proposed Amendment of Class E Airspace; Huntington, WV

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class E Airspace at Huntington, WV, as the Huntt Non-Directional Beacon (NDB) has been decommissioned and new Standard Instrument Approach Procedures (SIAPs) have been developed at Tri-State/Milton J Ferguson Field Airport. This action would enhance the safety and airspace management of Instrument Flight Rules (IFR) operations at the airport. This action also would update the geographic coordinates of the airport.

DATES: Comments must be received on or before December 2, 2011.

ADDRESSES: Send comments on this rule to: U.S. Department of Transportation, Docket Operations, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001; Telephone: 1–800–647–5527; Fax: 202–493–2251. You must identify the Docket Number FAA–2011–1057; Airspace Docket No. 11–AEA–21, at the beginning of your comments. You may also submit and review received comments through the Internet at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons are invited to comment on this rule by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal.

Communications should identify both docket numbers (FAA Docket No. FAA–2011–1057; Airspace Docket No. 11–AEA–21) and be submitted in triplicate to the Docket Management System (see **ADDRESSES** section for address and phone number). You may also submit comments through the Internet at *http://www.regulations.gov.*

Persons wishing the FAA to acknowledge receipt of their comments on this action must submit with those comments a self-addressed stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2011–1057; Airspace Docket No. 11–AEA–21.'' The postcard will be date/time stamped and returned to the commenter.

All communications received before the specified closing date for comments will be considered before taking action on the proposed rule. The proposal contained in this notice may be changed in light of the comments received. A report summarizing each substantive public contact with FAA personnel concerned with this rulemaking will be filed in the docket.

Availability of NPRMs

An electronic copy of this document may be downloaded from and comments submitted through *http://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office (see the **ADDRESSES** section for address and phone number) between 9 a.m. and 5 p.m., Monday through Friday, except Federal Holidays. An informal docket may also be examined during normal business hours at the office of the Eastern Service Center, Federal Aviation

Administration, room 350, 1701 Columbia Avenue, College Park, Georgia 30337.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking, (202) 267–9677, to request a copy of Advisory circular No. 11–2A, Notice of Proposed Rulemaking distribution System, which describes the application procedure.

The Proposal

The FAA is considering an amendment to Title 14, Code of Federal Regulations (14 CFR) part 71 to amend Class E airspace extending upward from 700 feet above the surface to support new Standard Instrument Approach Procedures developed at Tri-State/ Milton J Ferguson Field Airport, Huntington, WV. Airspace reconfiguration is necessary due to the decommissioning of the Huntt NDB and cancellation of the NDB approach, and for continued safety and management of IFR operations at the airport. The geographic coordinates of the airport also would be adjusted to coincide with the FAAs aeronautical database.

Class E airspace designations are published in Paragraph 6005 of FAA Order 7400.9V, dated August 9, 2011, and effective September 15, 2011, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document will be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this proposed rule, when promulgated, would not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This proposed rulemaking is promulgated under the authority described in Subtitle VII, Part, A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This proposed regulation is within the scope of that authority as it would amend Class E airspace at Tri-State/Milton J Ferguson Field Airport, Huntington, WV.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9V, Airspace Designations and Reporting Points, dated August 9, 2011, effective September 15, 2011, is amended as follows:

Paragraph 6005 Class E airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

AEA WV E Huntington, WV

Tri-State/Milton J. Ferguson Field Airport, Huntington, WV

(Lat. 38°22′02″N., long. 82°33′52″W.)

That airspace extending upward from 700 feet above the surface within an 8.2-mile radius of the Tri-State/Milton J Ferguson Field Airport.

Issued in College Park, Georgia, on October 5, 2011.

Barry A. Knight,

Acting Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2011–26473 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–13–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 112

[EPA–HQ–OPA–2011–0838; FRL–9481–3]

RIN 2050–AG59

Oil Pollution Prevention; Spill Prevention, Control, and Countermeasure (SPCC) Rule—Compliance Date Amendment for Farms

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to amend the date by which farms must prepare or amend, and implement their Spill Prevention, Control, and Countermeasure Plans, to May 10, 2013. In the ''Rules and Regulations'' section of this **Federal Register**, EPA is amending the date by which farms must prepare or amend, and implement their Spill Prevention, Control, and Countermeasure Plans to May 10, 2013, as a direct final rule without a prior proposed rule. If we receive no adverse comment, we will not take further action on this proposed rule.

DATES: Written comments must be received by November 2, 2011.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OPA–2011–0838, by mail to EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Comments may also be submitted electronically or through hand delivery/courier by following the detailed instructions in the **ADDRESSES** section of the direct final rule located in the rules section of this **Federal Register**.

FOR FURTHER INFORMATION CONTACT: For general information, contact the Superfund, TRI, EPCRA, RMP and Oil Information Center at (800) 424–9346 or TDD (800) 553–7672 (hearing impaired). In the Washington, DC metropolitan area, call (703) 412–9810 or TDD (703) 412–3323. For more detailed information on specific aspects of this final rule, contact either Lynn Beasley at (202) 564–1965 (*beasley.lynn@epa.gov*) or Mark W. Howard at (202) 564–1964 (*howard.markw@epa.gov*), U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0002, Mail Code 5104A.

SUPPLEMENTARY INFORMATION:

I. Why is EPA issuing this proposed rule?

This document proposes to take action on the date by which farms as defined in 40 CFR part 112 must prepare or amend, and implement their Spill Prevention, Control, and Countermeasure (SPCC) Plans. We have published a direct final rule to amend that date to May 10, 2013 in the ''Rules and Regulations'' section of this **Federal Register** because we view this as a noncontroversial action and anticipate no adverse comment. We have explained our reasons for this action in the preamble to the direct final rule.

If we receive no adverse comment, we will not take further action on this proposed rule. If we receive adverse comment, we will withdraw the direct final rule and it will not take effect. We would address all public comments in any subsequent final rule based on this proposed rule.

We do not intend to institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information, please see the information provided in the **ADDRESSES** section of this document.

II. Does this action apply to me?

Industry sector	NAICS code
Farms	111, 112
Government	92

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

III. What does this amendment do?

This proposed rule amends the date by which farms as defined in 40 CFR part 112 must prepare or amend, and implement their Spill Prevention, Control, and Countermeasure (SPCC) Plans to May 10, 2013.

On June 19, 2009 (74 FR 29136), EPA issued a final rule in the **Federal Register** that amended the dates by which facilities must prepare or amend their SPCC Plans, and implement those Plans to November 10, 2010. Then on October 14, 2010 (75 FR 63093), EPA issued a final rule in the **Federal Register** with a new compliance date of November 10, 2011, by which certain facilities must prepare or amend and implement their SPCC Plans, providing an additional year for the remaining facilities. This action further extends the compliance date to May 10, 2013 for farms as defined in 40 CFR 112.2. EPA is not extending the compliance date for any other facilities. The Agency recognizes that some facilities excluded from the extension of the compliance date may still require additional time to amend or prepare their SPCC Plans as a result of either non-availability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of the owner or operator. If so, the owner or operator of the facility may submit a written request for additional time to amend or prepare a SPCC Plan to the Regional Administrator in accordance with § 112.3(f).

IV. Statutory and Executive Order Reviews

For a complete discussion of all of the administrative requirements applicable to this action, see the direct final rule in the Rules and Regulations section of this **Federal Register**.

List of Subjects in 40 CFR Part 112

Oil pollution prevention, Farms, Compliance date, Reporting and recordkeeping requirements.

Dated: October 13, 2011.

Lisa P. Jackson,

Administrator.

[FR Doc. 2011–27045 Filed 10–17–11; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

48 CFR Parts 215, 225, and 252

RIN 0750–AH42

Defense Federal Acquisition Regulation Supplement: Contracting With the Canadian Commercial Corporation (DFARS Case 2011–D049)

AGENCY: Defense Acquisition Regulations System, Department of Defense (DoD).

ACTION: Proposed rule; correction.

SUMMARY: This document corrects the preamble to a proposed rule published in the **Federal Register** on October 4, 2011, regarding the requirement for the Canadian Commercial Corporation to submit data other than certified cost or pricing data. This correction clarifies background information concerning the origination of the proposed rule.

FOR FURTHER INFORMATION CONTACT: Amy G. Williams, telephone 703–602–0328.

Correction

In the proposed rule published October 4, 2011, at 76 FR 61296, make the following correction in the **SUPPLEMENTARY INFORMATION** section by replacing the first sentence, at paragraph I. Background, with the following sentence:

''This proposed rule solicits public comments on suggested DoD clarifications to DFARS subpart 215.4, discussed during bilateral integrated product team meetings of representatives from the U.S. Government and Canada.''

Dated: October 18, 2011.

Mary Overstreet,

Editor, Defense Acquisition Regulations System.

[FR Doc. 2011–26944 Filed 10–17–11; 8:45 am]

BILLING CODE 5001–06–P

Notices

Federal Register

Vol. 76, No. 201

Tuesday, October 18, 2011

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

ADMINISTRATIVE CONFERENCE OF THE UNITED STATES

Committee on Regulation

ACTION: Notice of public meeting.

SUMMARY: Notice is hereby given of a public meeting of the Committee on Regulation of the Assembly of the Administrative Conference of the United States (ACUS). The meeting will involve discussion of research conducted by Professor Wendy E. Wagner for ACUS's ''Science in the Administrative Process'' project. The committee will meet via a virtual, online Web forum extending over a period of approximately six weeks. Committee members will discuss Professor Wagner's research by posting comments to the forum and reading comments submitted to the forum by other persons. The public may participate by submitting comments electronically or by mail or fax.

DATES: The Web forum will be opened to both members of the Committee on Regulation and the public for submission and viewing of comments on November 2, 2011 at 9 a.m. The forum will remain open for submission of comments until December 15, 2011 at 5 p.m., unless it is announced on the forum Web site that the discussion has been completed earlier. After the period for receipt of comments has ended, the forum will remain available for viewing but will not accept additional comments.

ADDRESSES: The meeting will have no physical location. It will take place via an online discussion forum on the Administrative Conference Web site, which can be accessed at: *http://www.acus.gov/forum/.* The public may submit comments either electronically through the forum Web site or by mail or fax addressed to the Designated Federal Officer.

FOR FURTHER INFORMATION CONTACT: Reeve T. Bull, Designated Federal Officer for the Committee on Regulation, ACUS, 1120 20th Street, NW., Suite 706 South, Washington, DC 20036; Telephone 202–480–2080; Fax 202–386–7190.

SUPPLEMENTARY INFORMATION: Professor Wendy E. Wagner of the University of Texas Law School is conducting research for the ACUS project on ''Science in the Administrative Process.'' Previously, she presented a proposed outline to the Committee on Regulation and received feedback. Professor Wagner subsequently prepared a revised outline, and the purpose of this meeting is to enable committee discussion and feedback regarding the revised outline. The revised outline discusses Professor Wagner's research relating to (1) the transparency of agencies' reporting of their scientific research and (2) whether agencies allow scientists conducting research on their behalf to express dissenting viewpoints. The revised outline and any other documents associated with the committee meeting will be made available on the project Web page prior to the commencement of the committee meeting.

The committee will meet via a virtual, online Web forum extending over a period of approximately six weeks. *See* 41 CFR 102–3.140(e) (permitting meetings conducted ''in whole or part by * * * the Internet''). Committee members will discuss Professor Wagner's research by posting comments to the forum and reading comments submitted to the forum by other members of the committee and the public. All comments will be reviewed prior to posting by the Designated Federal Officer (DFO) acting as forum moderator. This virtual meeting will enable the committee to discuss the committee's business using modern communications tools in an open and transparent fashion.

The public will be able to view all comments on the forum. The public may also participate by submitting comments either electronically or by mail or fax via the contact information provided above. The DFO will review all comments received, both online and through other means of submission. The DFO will post all public comments received, excepting those that contain trade secret or other confidential information, or that are obscene, libelous, threatening, unrelated to the topic being discussed, or otherwise evidently inappropriate for posting. When submitting comments, please bear in mind that, because the Web forum will be moderated, it may take some time for comments to appear on the forum, particularly for comments submitted outside business hours.

The Web forum will be opened to both members of the Committee on Regulation and the public for submission and viewing of comments beginning on November 2, 2011 at 9 a.m. The forum will remain open for submission of comments until December 15, 2011 at 5 p.m., unless it is announced that the discussion has been completed earlier. Any earlier closing date will be announced on both the forum Web page and on the ''Science in the Administrative Process'' project page at least one week in advance. After the period for receipt of comments has ended, the forum will remain available for viewing but will not accept additional comments.

Complete details regarding the committee's online meeting, related research documents, and how to participate in the discussion (including information about accessing and navigating the Web forum and submitting comments for the committee's consideration) can be found on the ''Science in the Administrative Process'' project Web page on the ACUS Web site. Go to *http://www.acus.gov* and click on Research -> Conference Projects -> Science in the Administrative Process, or go directly to the following address: *http://www.acus.gov/research/the-conference-current-projects/science-in-the-administrative-process/.*

Dated: October 12, 2011.

Jonathan R. Siegel,

Director of Research & Policy.

[FR Doc. 2011–26848 Filed 10–17–11; 8:45 am]

BILLING CODE 6110–01–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

October 12, 2011.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the

Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), *OIRA_Submission@OMB.EOP.GOV* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Comments regarding these information collections are best assured of having their full effect if received within 30 days of this notification. Copies of the submission(s) may be obtained by calling (202) 720–8681.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Rural Housing Service

Title: 7 CFR part 1901–E, Civil Rights Compliance Requirements.

OMB Control Number: 0575–0018.

Summary of Collection: Rural Development (RD) is required to provide Federal financial assistance through its farmer, housing, and community and business programs on an equal opportunity basis. The laws implemented in 7 CFR part 1901–E, require the recipients of Rural Development's Federal financial assistance to collect various types of information by race, color, and national origin.

Need and Use of the Information: RD will use the information to monitor a recipient's compliance with the civil rights laws, and to determine whether or not service and benefits are being provided to beneficiaries on an equal opportunity basis. This information is made available to USDA officials, officials of other Federal agencies and to Congress for reporting purposes. Without the required information, RD and its recipient will lack the necessary documentation to demonstrate that their programs are being administered in a nondiscriminatory manner and in full compliance with the civil rights laws.

Description of Respondents: Individuals or households; not-for-profit institutions; business or other for-profit; farms; State, Local or Tribal Government.

Number of Respondents: 27,000.

Frequency of Responses: Reporting: On occasion.

Total Burden Hours: 560,276.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2011–26812 Filed 10–17–11; 8:45 am]

BILLING CODE 3410–XT–P

DEPARTMENT OF AGRICULTURE

National Agricultural Statistics Service

Notice of Intent to Request Revision and Extension of a Currently Approved Information Collection

AGENCY: National Agricultural Statistics Service, USDA.

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the intention of the National Agricultural Statistics Service (NASS) to request revision and extension of a currently approved information collection, the Field Crops Objective Yield Surveys. Revision to burden hours may be needed due to changes in the size of the target population, sampling design, and/or questionnaire length.

DATES: Comments on this notice must be received by December 19, 2011 to be assured of consideration.

ADDRESSES: You may submit comments, identified by docket number 0535–0088, by any of the following methods:

- *E-mail: omboffi cer@nass.usda.gov*. Include docket number above in the subject line of the message.
- *Fax:* (202) 720–6396.
- *Mail:* Mail any paper, disk, or CD–ROM submissions to: David Hancock, NASS Clearance Officer, U.S. Department of Agriculture, Room 5336 South Building, 1400 Independence Avenue SW., Washington, DC 20250–2024.
- *Hand Delivery/Courier: Hand deliver to:* David Hancock, NASS Clearance Officer, U.S. Department of Agriculture, Room 5336 South Building, 1400 Independence Avenue SW., Washington, DC 20250–2024.

FOR FURTHER INFORMATION CONTACT: Joseph T. Reilly, Associate Administrator, National Agricultural Statistics Service, U.S. Department of Agriculture, (202) 720–4333.

SUPPLEMENTARY INFORMATION:

Title: Field Crops Objective Yield.

OMB Control Number: 0535–0088.

Expiration Date of Approval: February 29, 2012.

Type of Request: To revise and extend a currently approved information collection for a period of three years.

Abstract: The primary objective of the National Agricultural Statistics Service (NASS) is to collect, prepare and issue State and national estimates of crop and livestock production, prices and disposition as well as economic statistics, farm numbers, land values, on-farm pesticide usage, pest crop management practices, as well as the Census of Agriculture. The Field Crops Objective Yield Surveys objectively predicts yields for corn, cotton, potatoes, soybeans, and wheat. Sample fields are randomly selected for these crops, plots are laid out, and periodic counts and measurements are taken and then used to forecast production during the growing season. Production forecasts are published in USDA Crop Production reports.

Authority: These data will be collected under the authority of 7 U.S.C. 2204(a). Individually identifiable data collected under this authority are governed by Section 1770 of the Food Security Act of 1985 as amended, 7 U.S.C. 2276, which requires USDA to afford strict confidentiality to non-aggregated data provided by respondents. This Notice is submitted in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3501, *et seq.*) and Office of Management and Budget regulations at 5 CFR part 1320. NASS also complies with OMB Implementation Guidance, ''Implementation Guidance for Title V of the E–Government Act, Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA),'' **Federal Register**, Vol. 72, No. 115, June 15, 2007, p. 33362.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average between 20 and 30 minutes per respondent.

Respondents: Farmers, ranchers, or farm managers.

Estimated Number of Respondents: 8,000.

Estimated Total Annual Burden on Respondents: 2,900 hours.

Copies of this information collection and related instructions can be obtained without charge from NASS Clearance Officer, at (202) 720–2248 or at *ombofficer@nass.usda.gov*.

Comments: Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on those who are to respond, through the use of appropriate automated, electronic, mechanical, technological or other forms of information technology collection methods.

All responses to this notice will become a matter of public record and be summarized in the request for OMB approval.

Signed at Washington, DC, September 21, 2011.

Joseph T. Reilly,

Associate Administrator.

[FR Doc. 2011–26948 Filed 10–17–11; 8:45 am]

BILLING CODE 3410–20–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Pacific Islands Region Permit Family of Forms.

OMB Control Number: 0648–0490.

Form Number(s): NA.

Type of Request: Regular submission (revision and extension of a current information collection).

Number of Respondents: 167.

Average Hours Per Response: Western Pacific permits, 30 minutes; American Samoa limited access permits, 45 minutes; appeals, 2 hours.

Burden Hours: 124.

Needs and Uses: The National Marine Fisheries Service (NMFS) Pacific Islands Region (PIR) manages the United States (U.S.) Fisheries of the Exclusive Economic Zone (EEZ) in the western Pacific under five fishery management plans (FMP), prepared by the Western Pacific Fishery Management Council (Council) pursuant to the Magnuson-Stevens Fishery Conservation and Management Act (MSA). The regulations implementing the FMP are found at 50 CFR part 665.

The permitting requirements at 50 CFR part 665 form the basis for this collection of information. PIR requests information from participants in the fisheries and interested persons. This information is needed for permit issuance, to identify participants in the fisheries, and to help measure impacts of management controls on the participants in the fisheries of the EEZ in the western Pacific.

The revision involves the elimination of Hawaii longline shallow-set certificate requests and northwest Hawaiian islands bottomfish limited entry permits due to regulatory changes, and moving western Pacific crustacean permit applications to another information collection.

Affected Public: Business or other for-profit organizations.

Frequency: Annually.

Respondent's Obligation: Mandatory.

OMB Desk Officer: *OIRA_Submission@omb.eop.gov.*

Copies of the above information collection proposal can be obtained by calling or writing Diana Hynek, Departmental Paperwork Clearance Officer, (202) 482–0266, Department of Commerce, Room 6616, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *OIRA_Submission@omb.eop.gov.*

Dated: October 12, 2011.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. 2011–26841 Filed 10–17–11; 8:45 m]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Individual Fishing Quotas for Pacific Halibut and Sablefish in the Alaska Fisheries.

OMB Control Number: 0648–0272.

Form Number(s): NA.

Type of Request: Regular submission (revision and extension of a current information collection).

Number of Respondents: 1,686.

Average Hours per Response: Application for a non-profit corporation to be designated as a Community Quota Entity (CQE), 200 hours; application for eligibility to receive quota share/individual fishing quota (QS/IFQ), identification of shareholder interest, application for transfer of QS/IFQ, 2 hours; application for hired master permit, application for registered buyer permit, designated beneficiary form, 30 minutes; prior notice of landing, 12 minutes; landing report, 18 minutes, administrative waiver, 15 minutes, dockside sales receipt, 6 minutes.

Burden Hours: 9,946.

Needs and Uses: This request is for revision and extension of a current information collection.

The Pacific Halibut and Sablefish Individual Fishing Quota (IFQ) Program was developed to reduce fishing capacity that had increased during years of management as an open access fishery, while maintaining the social and economic character of the fixed gear fishery that is relied on as a source of revenue for coastal communities in Alaska. The Halibut and Sablefish IFQ Program provides economic stability for the commercial hook-and-line fishery while reducing many of the conservation and management problems commonly associated with open access. The IFQ Program for sablefish and Pacific halibut fixed gear provides each fisherman a catch quota that can be used any time during the open season. Individual shares are intended to allow fishermen to set their own pace and adjust their fishing effort. The IFQ Program is intended to reduce the premium that was traditionally placed on speed, allowing fishermen to pay more attention to efficiency and product quality. The IFQ Program consists of three parts: IFQ halibut and sablefish, Western Alaska Community Development Quota (CDQ) halibut, and Gulf of Alaska (GOA) IFQ community quota share.

Program changes/revisions consist of removal of duplicative forms/information collections and changes to notarization requirements (removing for some information collections and adding for one).

Affected Public: Business or other for-profit organizations; not-for-profit institutions.

Frequency: Annually and on occasion.

Respondent's Obligation: Mandatory.

OMB Desk Officer: *OIRA_Submission@omb.eop.gov.*

Copies of the above information collection proposal can be obtained by calling or writing Diana Hynek, Departmental Paperwork Clearance Officer, (202) 482–0266, Department of Commerce, Room 6616, 14th and Constitution Avenue, NW., Washington, DC 20230 (or via the Internet at *dHynek@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *OIRA_Submission@omb.eop.gov.*

Dated: October 12, 2011.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. 2011–26851 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–570–978]

High Pressure Steel Cylinders From the People's Republic of China: Preliminary Affirmative Countervailing Duty Determination and Alignment of Final Countervailing Duty Determination With Final Antidumping Duty Determination

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce preliminarily determines that countervailable subsidies are being provided to producers and exporters of high pressure steel cylinders from the People's Republic of China. For information on the estimated subsidy rates, see the ''Suspension of Liquidation'' section of this notice.

DATES: *Effective Date:* October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Christopher Siepmann or David Layton, AD/CVD Operations, Office 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–7958 and (202) 482–0371, respectively.

SUPPLEMENTARY INFORMATION:

Case History

The following events have occurred since the publication of the Department of Commerce's (''Department'') notice of initiation in the **Federal Register.** *See High Pressure Steel Cylinders From the People's Republic of China; Initiation of Countervailing Duty Investigation,* 76 FR 33239 (June 8, 2011) (''*Initiation Notice''*), and the accompanying Initiation Checklist.

On July 5, 2011, the U.S. International Trade Commission (''ITC'') published its affirmative preliminary determination that there is a reasonable indication that an industry in the United States is materially injured by reason of allegedly subsidized imports of high pressure steel cylinders (''steel cylinders'') from the People's Republic of China (''PRC''). *See High Pressure Steel Cylinders From China,* 76 FR 38697 (July 1, 2011).

On July 13, 2011, we selected Beijing Tianhai Industry Co., Ltd. (''BTIC'') as the mandatory respondent in this proceeding. *See* Memorandum to Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, ''Selection of Respondents for the Countervailing Duty Investigation of High Pressure Steel Cylinders from the People's Republic of China'' (July 13, 2011) (''Respondent Selection Memo''). The public version of this memorandum and all other memoranda referenced in this notice are on file electronically via Import Administration's Antidumping and Countervailing Duty Centralized Electronic Service System (''IA ACCESS''). Access to IA ACCESS is available in the Department's Central Records Unit in Room 7046 of the main Department building.

On July 19, 2011, the Department published a postponement of the deadline for the preliminary determination in this Investigation until October 11, 2011. *See High Pressure Steel Cylinders From the People's Republic of China: Postponement of Preliminary Determination in the Countervailing Duty Investigation,* 76 FR 42682 (July 19, 2011).

On July 20, 2011, we issued a questionnaire to BTIC and the Government of the People's Republic of China (''GOC''). We received responses from BTIC and the GOC on September 2, and September 7, 2011, respectively. Supplemental questionnaires were sent to BTIC on September 15, and 23, 2011, and we received responses September 26, and September 28, and October 3, 2011. We sent supplemental questionnaires to the GOC on September 20, and September 23, 2011, and received a response to the former on September 27, 2011. We currently expect to receive a response to our September 23, 2011 questionnaire from the GOC on or before October 14, 2011.

We received pre-preliminary comments from BTIC and Norris Cylinder Co. (''Petitioner'') on October 4, and October 6, 2011, respectively. We did not have time to analyze these comments for this preliminary determination.

The Department also received a questionnaire response from Zhejiang Jindun Pressure Container Co., Ltd. (''Jindun'') on September 2, 2011. Jindun was not selected for individual examination in this investigation and its voluntary response has not been analyzed. *See* Respondent Selection Memo.

Period of Investigation

The period for which we are measuring subsidies, *i.e.,* the period of investigation (''POI''), is January 1, 2010, through December 31, 2010.

Scope Comments

In accordance with the preamble to the Department's regulations, we set aside a period of time in our *Initiation Notice* for parties to raise issues regarding product coverage, and encouraged all parties to submit comments within 20 calendar days of publication of that notice. *See Antidumping Duties; Countervailing Duties,* 62 FR 27296, 27323 (May 19, 1997), and *Initiation Notice,* 76 FR at 33239. We did not receive any comments.

Scope of the Investigation

The merchandise covered by the scope of the investigation is seamless steel cylinders designed for storage or transport of compressed or liquefied gas (''high pressure steel cylinders''). High pressure steel cylinders are fabricated of chrome alloy steel including, but not limited to, chromium-molybdenum steel or chromium magnesium steel, and have permanently impressed into the steel, either before or after importation, the symbol of a U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (''DOT'')-approved high pressure steel cylinder manufacturer, as well as an approved DOT type marking of DOT 3A, 3AX, 3AA, 3AAX, 3B, 3E, 3HT, 3T, or DOT–E (followed by a specific exemption number) in accordance with the requirements of sections 178.36 through 178.68 of Title 49 of the Code of Federal Regulations, or any subsequent amendments thereof. High pressure steel cylinders covered by these investigations have a water

capacity up to 450 liters, and a gas capacity ranging from 8 to 702 cubic feet, regardless of corresponding service pressure levels and regardless of physical dimensions, finish or coatings.

Excluded from the scope of the investigation are high pressure steel cylinders manufactured to UN–ISO–9809–1 and 2 specifications and permanently impressed with ISO or UN symbols. Also excluded from the investigation are acetylene cylinders, with or without internal porous mass, and permanently impressed with 8A or 8AL in accordance with DOT regulations.

Merchandise covered by the investigation is classified in the Harmonized Tariff Schedule of the United States (''HTSUS'') under subheading 7311.00.00.30. Subject merchandise may also enter under HTSUS subheadings 7311.00.00.60 or 7311.00.00.90. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the merchandise under the investigation is dispositive.

Alignment of Final Determination

On June 8, 2011, the Department initiated the antidumping duty (''AD'') and countervailing duty (''CVD'') investigations of steel cylinders from the PRC. *See High Pressure Steel Cylinders from the People's Republic of China: Initiation of Antidumping Duty Investigation,* 76 FR 33213 (June 8, 2011) and *Initiation Notice* (for the CVD investigation). The scope of the merchandise being covered is the same for both the AD and CVD investigations. On September 27, 2011, Petitioner submitted a letter, in accordance with section 705(a)(1) of the Act, requesting alignment of the final CVD determination with the final determination in the companion AD investigation. Therefore, in accordance with section 705(a)(1) of the Act and 19 CFR 351.210(b)(4), the final CVD determination will be issued on the same date as the final AD determination, which is currently scheduled to be issued on or about February 21, 2012.

Application of the Countervailing Duty Law to Imports From the PRC

On October 25, 2007, the Department published *Coated Free Sheet Paper from the People's Republic of China: Final Affirmative Countervailing Duty Determination,* 72 FR 60645 (October 25, 2007) (''*CFS from the PRC*''), and the accompanying Issues and Decision Memorandum (''CFS Decision Memo''). In *CFS from the PRC*, the Department found that given the substantial differences between the Soviet-style economies and China's economy in recent years, the Department's previous decision not to apply the CVD law to these Soviet-style economies does not act as a bar to proceeding with a CVD investigation involving products from China.

See CFS Decision Memo, at Comment 6. The Department has affirmed its decision to apply the CVD law to the PRC in subsequent final determinations. *See, e.g., Circular Welded Carbon Quality Steel Pipe from the People's Republic of China: Final Affirmative Countervailing Duty Determination and Final Affirmative Determination of Critical Circumstances,* 73 FR 31966 (June 5, 2008), and accompanying Issues and Decision Memorandum (''CWP Decision Memo''), at Comment 1.

Additionally, for the reasons stated in the CWP Decision Memo, we are using the date of December 11, 2001, the date on which the PRC became a member of the World Trade Organization, as the date from which the Department will identify and measure subsidies in the PRC. *See* CWP Decision Memo, at Comment 2.

Subsidies Valuation Information

Allocation Period

The average useful life (''AUL'') period in this proceeding, as described in 19 CFR 351.524(d)(2), is 12 years according to the U.S. Internal Revenue Service's 1977 Class Life Asset Depreciation Range System. *See* U.S. Internal Revenue Service Publication 946 (2008), *How to Depreciate Property,* at Table B–2: Table of Class Lives and Recovery Periods. No party in this proceeding has disputed this allocation period.

Attribution of Subsidies

The Department's regulations at 19 CFR 351.525(b)(6)(i) state that the Department will normally attribute a subsidy to the products produced by the corporation that received the subsidy. However, 19 CFR 351.525(b)(6)(ii)–(v) directs that the Department will attribute subsidies received by certain other companies to the combined sales of those companies if (1) cross-ownership exists between the companies, and (2) the cross-owned companies produce the subject merchandise, are a holding or parent company of the subject company, produce an input that is primarily dedicated to the production of the downstream product, or transfer a subsidy to a cross-owned company.

According to 19 CFR 351.525(b)(6)(vi), cross-ownership exists between two or more corporations where one corporation can use or direct the individual assets of the other corporation(s) in essentially the same ways it can use its own assets. This regulation states that this standard will normally be met where there is a majority voting interest between two corporations or through common ownership of two (or more) corporations. The Court of International Trade (''CIT'') has upheld the Department's authority to attribute subsidies based on whether a company could use or direct the subsidy benefits of another company in essentially the same way it could use its own subsidy benefits. *See Fabrique de Fer de Charleroi, SA* v. *United States,* 166 F. Supp. 2d 593, 600–604 (CIT 2001).

As of this preliminary determination, BTIC has responded to the Department's original and supplemental questionnaires on behalf of itself; Tianjin Tianhai High Pressure Container Co., Ltd., (''Tianjin Tianhai''); Langfang Tianhai High Pressure Container Co., Ltd. (''Langfang Tianhai'') and Beijing Jingcheng Machinery Electric Holding Co., Ltd. (''Jingcheng Holding''). We preliminarily determine that BTIC, Tianjin Tianhai, Langfang Tianhai and Jingcheng Holding are cross-owned within the meaning of 19 CFR 351.525(b)(6)(vi). Because the nature of the relationships between these companies is proprietary, we have discussed the basis for our cross-ownership determination separately. *See* Memorandum from Christopher Siepmann to Susan Kuhbach, ''Preliminary Results Calculation Memorandum for Beijing Tianhai Industry Co., Ltd (October 11, 2011) (''Prelim Calc Memo'').

BTIC, Tianjin Tianhai, and Langfang Tianhai are producers of subject merchandise. Accordingly, we are attributing subsidies received by BTIC, Tianjin Tianhai, and Langfang Tianhai to the combined sales of the three companies, excluding sales to other cross-owned companies. Jingcheng Holding is a holding company within the meaning of 19 CFR 351.525(b)(6)(iii). Under 19 CFR 351.525(b)(6)(iii), the Department will attribute subsidies received by a holding company to the consolidated sales of the holding company and its subsidiaries; however, Jingcheng Holding reported that it did not receive benefits under any investigated program during the POI and the allocation period, except for the investigated programs for which more information is needed. *See* ''Programs For Which More Information is Required'' below.

In our first supplemental questionnaire to BTIC, we asked questions about certain affiliates that

may have met the cross-ownership standard under 19 CFR 351.525(b)(6)(vi). Based on BTIC's responses, we preliminarily determine that none of these affiliates met both the cross-ownership standard of 19 CFR 351.525(b)(6)(vi) and one or more of the attribution standards under 19 CFR 351.525(b)(6)(ii)-(v). Thus, we have not included any subsidies to these companies in the subsidy calculations.

Also in our first supplemental questionnaire to BTIC, we asked questions regarding a shareholder that used to hold a controlling interest in BTIC and may have met the attribution standard under 19 CFR 351.525(b)(6)(iii). BTIC reported that this company did not receive non-recurring subsidies during the period that it was cross-owned with BTIC.

Analysis of Programs

Based upon our analysis of the petition and the responses to our questionnaires, we preliminarily determine the following:

I. Programs Preliminarily Determined To Be Countervailable

A. ''Two Free, Three Half'' Program for Foreign-Invested Enterprises (''FIEs'')

Under Article 8 of the FIE Tax Law, an FIE that is ''productive'' and scheduled to operate for more than ten years may be exempted from income tax in the first two years of profitability and pay income taxes at half the standard rate for the next three years. According to the GOC, the ''Two Free, Three Half'' program was terminated effective January 1, 2008, by the Enterprise Income Tax Law but companies already enjoying the preference were permitted to continue paying taxes at reduced rates. Tianjin Tianhai paid taxes at a reduced rate under this program during the POI.

The Department has previously found the ''Two Free, Three Half'' program to confer countervailable subsidies. *See* CFS Decision Memo at 11–12; *see also Certain Seamless Carbon and Alloy Steel Standard, Line, and Pressure Pipe from the People's Republic of China: Final Affirmative Countervailing Duty Determination, Final Affirmative Critical Circumstances Determination,* 75 FR 57444 (September 21, 2010), and accompanying Issues and Decision Memorandum at 25.

Consistent with the earlier cases, we preliminarily determine that the ''Two Free, Three Half'' income tax exemption/reduction confers a countervailable subsidy. The exemption/reduction is a financial contribution in the form of revenue forgone by the GOC and it provides a benefit to the recipient in the amount of the tax savings. *See* section 771(5)(D)(ii) of the Act and 19 CFR 351.509(a)(1). We also determine that the exemption/reduction afforded by the program is limited as a matter of law to certain enterprises, *i.e.,* productive FIEs, and, hence, is specific under section 771(5A)(D)(i) of the Act.

To calculate the benefit, we treated the income savings enjoyed by Tianjin Tianhai as a recurring benefit, consistent with 19 CFR 351.524(c)(1). To compute the amount of the tax savings, we compared Tianjin Tianhai's tax rate to the rate it would have paid in the absence of the program. We divided Tianjin Tianhai's tax savings for the return filed during the POI by the combined sales (exclusive of inter-company sales) of BTIC, Tianjin Tianhai and Langfang Tianhai during the POI, in accordance with 19 CFR 351.525(b)(6)(ii).

On this basis, we preliminarily determine that BTIC received a countervailable subsidy of 0.01 percent *ad valorem* under this program.

B. Enterprise Income Tax Rate Reduction in the Tianjin Port Free Trade Zone

Under Article 4 of the ''Official Reply of the State Council Concerning the Establishment of the Tianjin Port Free Trade Zone,'' FIEs located in the Tianjin Port Free Trade Zone were permitted to pay a reduced income tax at a rate of 15 percent. According to the GOC, this program terminated on January 1, 2008, but companies that enjoyed the reduced tax rate are gradually transitioning to the national tax rate of 25 percent. Consequently, Tianjin Tianhai paid taxes at a reduced rate of 20 percent under this program during the POI.

We preliminarily determine that the Enterprise Income Tax Rate Reduction in the Tianjin Port Free Trade Zone program confers a countervailable subsidy. The reduction is a financial contribution in the form of revenue forgone by the GOC and it provides a benefit to the recipient in the amount of the tax savings. *See* section 771(5)(D)(ii) of the Act and 19 CFR 351.509(a)(1). We also determine that the exemption/reduction afforded by the program is regionally specific under section 771(5A)(D)(iv) of the Act, because it is limited to companies that are located in the Tianjin Port Free Trade Zone.

To calculate the benefit, we treated the income tax savings enjoyed by Tianjin Tianhai as a recurring benefit, consistent with 19 CFR 351.524(c)(1). To compute the amount of the tax savings, we compared Tianjin Tianhai's tax rate to the rate it would have paid in the absence of the program. We divided Tianjin Tianhai's tax savings for the return filed during the POI by the combined sales of BTIC, Tianjin Tianhai and Langfang Tianhai (exclusive of inter-company sales) during the POI, in accordance with 19 CFR 351.525(b)(6)(ii).

On this basis, we preliminarily determine that BTIC received a countervailable subsidy of 0.01 percent *ad valorem* under this program.

C. Import Tariff and VAT Exemptions for FIEs and Certain Domestic Enterprises Using Imported Equipment in Encouraged Industries

Enacted in 1997, the Circular of the State Council on Adjusting Tax Policies on Imported Equipment (GUOFA No. 37) (Circular No. 37) exempts both FIEs and certain domestic enterprises from the VAT and tariffs on imported equipment used in their production so long as the equipment does not fall into prescribed lists of non-eligible items. The National Development and Reform Commission or its provincial branch provides a certificate to enterprises that receive the exemption. The objective of the program is to encourage foreign investment and to introduce foreign advanced technology equipment and industry technology upgrades. BTIC and Langfang Tianhai received VAT and tariff exemptions under this program as FIEs. The Department has previously found VAT and tariff exemptions under this program to confer countervailable subsidies. *See* CFS Decision Memo at 13–14; *see also Certain Seamless Carbon and Alloy Steel Standard, Line, and Pressure Pipe from the People's Republic of China: Final Affirmative Countervailing Duty Determination, Final Affirmative Critical Circumstances Determination,* 75 FR 57444 (September 21, 2010), and accompanying Issues and Decision Memorandum at 23–25.

Consistent with the earlier cases, we preliminarily determine that VAT and tariff exemptions on imported equipment confer a countervailable subsidy. The exemptions are a financial contribution in the form of revenue forgone by the GOC and they provide a benefit to the recipient in the amount of the VAT and tariff savings. *See* section 771(5)(D)(ii) of the Act and 19 CFR 351.510(a)(1). As described above, FIEs and certain domestic enterprises are eligible to receive VAT and tariff exemptions under this program. We also determine that the VAT and tariff exemptions afforded by the program are specific under section 771(5A)(D)(iii)(I) of the Act because the program is limited to certain enterprises, *i.e.,* FIEs

and domestic enterprises involved in ''encouraged'' projects. *See* CFS Decision Memo at Comment 16.

Normally, we treat exemptions from indirect taxes and import charges, such as the VAT and tariff exemptions, as recurring benefits, consistent with 19 CFR 351.524(c)(1) and allocate the benefits to the year in which they were received. However, when an indirect tax or import charge exemption is provided for, or tied to, the capital structure or capital assets of a firm, the Department may treat it as a non-recurring benefit and allocate the benefit to the firm over the AUL. *See* 19 CFR 351.524(c)(2)(iii) and 19 CFR 351.524(d)(2). In the instant investigation, BTIC and Langfang Tianhai have provided a list of VAT and tariff exemptions that they received for capital equipment imported after December 11, 2001. Based on BTIC's information, we preliminarily determine that the VAT and tariff exemptions were for capital equipment.

To calculate the countervailable subsidy, we used our standard methodology for non-recurring grants. *See* 19 CFR 351.524(b). We preliminarily determine that, for each year in which BTIC and Langfang Tianhai received benefits under this program, the amount received did not exceed 0.5 percent of relevant sales for that year. Pursuant to 19 CFR 351.524(b)(2), we have expensed the entire amount received for both firms to the years in which they received the exemptions.

On this basis, we preliminarily determine that BTIC received a countervailable benefit of 0.02 percent ad valorem for this program.

D. Provision of Hot-Rolled Steel for Less Than Adequate Remuneration (''LTAR'')

BTIC reported purchasing hot-rolled steel, although not for use in the production of subject merchandise, and identified the producers of the hot-rolled steel it purchased during the POI. The GOC reported that these hot-rolled steel producers are majority owned and controlled by the GOC. In tires from the PRC, the Department determined that majority government ownership of an input producer is sufficient to qualify it as an ''authority.'' *See Certain New Pneumatic Off-the-Road Tires From the People's Republic of China: Final Affirmative Countervailing Duty Determination and Final Negative Determination of Critical Circumstances,* 73 FR 40480 (July 15, 2008), and accompanying Issues and Decision Memorandum at 10. Thus, we preliminarily determine these suppliers are ''authorities'' within the meaning of section 771(5)(B) of the Act.

We preliminarily determine that the GOC is conferring a countervailable subsidy through its provision of hot-rolled steel for LTAR. We determine that authorities are providing a good and, hence, a financial contribution under section 771(5)(D)(iii) of the Act and that a benefit is being conferred because the hot-rolled steel is being provided for LTAR, as explained below. Further, the GOC has reported that hot-rolled steel is used by a ''wide variety of steel consuming industries.'' Because hot-rolled steel is only provided to steel consuming industries, we preliminarily determine that the subsidy is being provided to a limited number of industries and is, therefore, specific. *See* section 771(5A)(D)(iii)(I) of the Act. This finding is consistent with prior Department determinations. *See, e.g.,* CWP Decision Memo at 9.

The Department's regulations at 19 CFR 351.511(a)(2) set out the bases for identifying an appropriate market-based benchmark for measuring the adequacy of the remuneration of a government provided good or service. The potential benchmarks listed in this regulation, in order of preference are: (1) Market prices from actual transactions within the country under investigation for the government-provided good (*e.g.,* actual sales, actual imports, or competitively run government auctions) (''tier one'' benchmarks); (2) world market prices that would be available to purchasers in the country under investigation (''tier two'' benchmarks); or (3) prices consistent with market principles based on an assessment by the Department of the government-set price (''tier three'' benchmarks). As we explained in softwood lumber from Canada, the preferred benchmark in the hierarchy is an observed market price from actual transactions within the country under investigation because such prices generally would be expected to reflect most closely the prevailing market conditions of the purchaser under investigation. *See Notice of Final Affirmative Countervailing Duty Determination and Final Negative Critical Circumstances Determination: Certain Softwood Lumber Products From Canada,* 67 FR 15545 (April 2, 2002), and accompanying Issues and Decision Memorandum at ''Analysis of Programs, Provincial Stumpage Programs Determined to Confer Subsidies, Benefit.''

Beginning with tier one, we must determine whether the prices from actual sales transactions involving Chinese buyers and sellers are significantly distorted. As explained in the CVD Preamble: ''Where it is reasonable to conclude that actual transaction prices are significantly distorted as a result of the government's involvement in the market, we will resort to the next alternative {tier two} in the hierarchy.'' *See Countervailing Duties; Final Rule,* 63 FR 65348, 65377 (November 25, 1998) (''CVD Preamble''). The CVD Preamble further recognizes that distortion can occur when the government provider constitutes a majority, or in certain circumstances, a substantial portion of the market.

Based on the GOC's response, companies that the GOC classified as state-owned accounted for 70 percent of hot-rolled steel production in the PRC during the POI and, therefore, government-owned providers constitute a majority of the market. We also note that imports as a share of domestic consumption are insignificant. We preliminarily determine that domestic prices in the PRC for hot-rolled steel are distorted such that they cannot be used as a tier one benchmark. For the same reasons, we determine that import prices into the PRC cannot serve as a benchmark.

Turning to tier two benchmarks, *i.e.,* world market prices available to purchasers in the PRC, both Petitioner and BTIC have submitted prices that they suggest are appropriate bases for constructing a benchmark. Based on our review of the proposed benchmarks, we are preliminarily relying on prices from both MEPS International (''MEPS'') and the Steel Business Briefing (''SBB'') for hot-rolled strip, hot-rolled coil, and hot-rolled plate/sheet. Pursuant to 19 CFR 351.511(a)(2)(ii) we are averaging the selected prices. Since ocean freight to the PRC is to be added into the benchmark price (see below), we did not rely on any SBB or MEPS prices price that included ocean freight, thereby ensuring that ocean freight would not be counted twice.

Under 19 CFR 351.511(a)(2)(iv), when measuring the adequacy of remuneration under tier one or tier two, the Department will adjust the benchmark price to reflect the price that a firm actually paid or would pay if it imported the product, including delivery charges and import duties. Regarding delivery charges, we have included ocean freight and the freight charges that would be incurred to deliver hot-rolled steel to BTIC's plants. We have also added import duties, as reported by the GOC, and the value-added tax (''VAT'') applicable to imports of hot-rolled steel into the PRC. *See* Prelim Calc Memo for a full explanation of how we derived the benchmark. We have compared these prices to BTIC's actual purchase prices, including taxes and delivery charges.

Based on this comparison, we preliminarily determine that hot-rolled steel was provided for LTAR and that a subsidy exists in the amount of the difference between the benchmark and what BTIC paid. *See* 19 CFR 351.511(a).

On this basis, we preliminarily determine that BTIC received a countervailable subsidy of 0.13 percent *ad valorem* under this program.

E. Provision of Seamless Tube Steel for LTAR

BTIC reported purchasing seamless tube steel for the production of subject merchandise and identified several producers of this input. The GOC provided ownership information indicating that certain of these seamless tube steel producers are state-owned enterprises (''SOEs''). Thus, we preliminarily determine these producers are ''authorities'' within the meaning of section 771(5)(B) of the Act. Regarding one seamless tube steel producer, we are seeking further information. *See* ''Case History'' above regarding the outstanding supplemental questionnaire to the GOC. Thus, for this preliminary determination, we are not including BTIC's purchases of seamless tube steel produced by this company in our calculation.

We preliminarily determine that the GOC is conferring a countervailable subsidy through its provision of seamless tube steel for LTAR. We determine that authorities are providing a good and, hence, a financial contribution under section 771(5)(D)(iii) of the Act and that a benefit is being conferred because the seamless tube steel is being provided for LTAR, as explained below. Further, the GOC has reported that seamless tube steel is used by a ''wide variety of steel consuming industries,'' and the GOC specifically identified the following uses: plumbing and heating systems, air conditioning units, sprinklers, and in the construction and repair of refineries and chemical plants. Because seamless tube steel is only provided to steel consuming industries, we preliminarily determine that the subsidy is being provided to a limited number of industries and is, therefore, specific. *See* section 771(5A)(D)(iii)(I) of the Act.

We have selected our benchmark for measuring the adequacy of the remuneration in accordance with 19 CFR 351.511(a)(2). With regard to tier one, market prices from actual transactions within the country under investigation, the GOC has reported that companies that it has designated as state-owned accounted for 38 percent of seamless tube steel production in the PRC during the POI. We determine that this level of government ownership is substantial. Combining this with the fact that imports as a share of domestic consumption are insignificant, we preliminarily determine that domestic prices in the PRC for seamless tube steel are distorted such that they cannot be used as a tier one benchmark. For the same reasons, we determine that import prices into the PRC cannot serve as a benchmark.

Turning to tier two benchmarks, *i.e.,* world market prices available to purchasers in the PRC, both Petitioner and BTIC have submitted prices that they suggest are appropriate bases for constructing a benchmark. Based on our review of the proposed benchmarks, we are preliminarily relying on FOB and export prices from Steel Orbis for seamless tube steel. Pursuant to 19 CFR 351.511(a)(2)(ii), we are averaging the selected prices. Since ocean freight to the PRC is to be added into the benchmark price (see below), we did not rely on any prices that included ocean freight, thereby ensuring that ocean freight would not be counted twice.

As explained above, the Department adjusts the benchmark price to include delivery charges and import duties. Regarding delivery charges, we have included ocean freight and the freight charges that would be incurred to deliver seamless tube steel to BTIC's plants. We have also added import duties, as reported by the GOC, and the VAT applicable to imports of seamless tube steel into the PRC. *See* Prelim Calc Memo for a full explanation of how we derived the benchmark. We have compared these prices to BTIC's actual purchase prices, including taxes and delivery charges.

Based on this comparison, we preliminarily determine that seamless tube steel was provided for LTAR and that a subsidy exists in the amount of the difference between the benchmark and what BTIC paid. *See* 19 CFR 351.511(a).

On this basis, we preliminarily determine that BTIC received a countervailable subsidy of 22.14 percent *ad valorem* under this program.

F. Provision of Standard Commodity Steel Billets and Blooms, and High-Quality Chromium Molybdenum Alloy Steel Billets and Blooms for LTAR

BTIC reported purchasing standard commodity steel billets and blooms (''commodity billets'') and high-quality chromium molybdenum alloy steel billets and blooms (''CrMo billets'') (collectively, ''billets'') for the production of subject merchandise and identified several producers of these inputs. The GOC provided ownership information for these input producers indicating that all are directly or indirectly majority owned by the GOC. As explained above, the Department has determined that majority government ownership of an input producer is sufficient to qualify it as an ''authority.''

We preliminarily determine that the GOC is conferring a countervailable subsidy through its provision of billets for LTAR. We determine that authorities are providing a good and, hence, a financial contribution under section 771(5)(D)(iii) of the Act and that a benefit is being conferred because the billets are being provided for LTAR, as explained below. Further, the GOC has reported that billets are used by a ''wide variety of steel consuming industries.'' Because billets are provided only to steel consuming industries, we preliminarily determine that the subsidy is being provided to a limited number of industries and is, therefore, specific. *See* section 771(5A)(D)(iii)(I) of the Act.

We have selected our benchmark for measuring the adequacy of the remuneration in accordance with 19 CFR 351.511(a)(2). With regard to tier one, market prices from actual transactions within the country under investigation, the GOC has reported that companies it designates as government-owned accounted for 60 percent of crude steel production in the PRC during the POI. (Because the PRC's State Statistical Bureau does not track production of commodity billets or high-quality chromium molybdenum alloy steel billets the GOC has responded with information on crude steel production.) Therefore, government-owned providers constitute a majority of the market. *See* CVD Preamble, 63 FR at 65377. We also note that imports as a share of domestic consumption are insignificant. We preliminarily determine that domestic prices in the PRC for billets are distorted such that they cannot be used as a tier one benchmark. For the same reasons, we determine that import prices into the PRC cannot serve as a benchmark.

Turning to tier two benchmarks, *i.e.,* world market prices available to purchasers in the PRC, the Department has been unable to locate benchmark prices for CrMo billets, and no world market prices for CrMo billets were placed on the record of this investigation. Therefore, we have relied on a single benchmark for both types of billets. Both Petitioner and BTIC have submitted billet prices. Based on our review of the proposed benchmarks, we are preliminarily relying on FOB and export prices from the SBB and the London Metal Exchange for billets. Pursuant to 19 CFR 351.511(a)(2)(ii), we

are averaging the submitted prices. Since ocean freight to the PRC is to be added into the benchmark price (see below), we did not rely on any prices that included ocean freight, thereby ensuring that ocean freight would not be counted twice.

As explained above, the Department adjusts the benchmark price to include delivery charges and import duties. Regarding delivery charges, we have included ocean freight and the freight charges that would be incurred to deliver billets to BTIC's plants. We have also added import duties, as reported by the GOC, and the VAT applicable to imports of billets into the PRC. *See* Prelim Calc Memo for a full explanation of how we derived the benchmark. We have compared these prices to BTIC's actual purchase prices, including taxes and delivery charges.

Based on this comparison, we preliminarily determine that commodity billets were provided for LTAR and that a subsidy exists in the amount of the difference between the benchmark and what the respondents paid. *See* 19 CFR 351.511(a). We preliminarily determine that BTIC received a countervailable subsidy of 0.03 percent *ad valorem* with respect to the provision of this input. Regarding CrMo billets, we preliminarily determine that BTIC did not receive a benefit from its purchases during the POI. However, we intend to continue seeking a benchmark specific to CrMo billets and will consider whether altering our methodology for the final determination is appropriate.

II. Programs Preliminarily Determined To Be Not Countervailable

A. Provision of Land-Use Rights in the Tianjin Port Free Trade Zone for LTAR

BTIC submitted information regarding Tianjin Tianhai's purchase of land-use rights showing that Tianjin Tianhai is located in the Tianjin Port Free Trade Zone (''TPFTZ'') and that the company purchased its land-use rights from the land bureau for that Zone. Additionally, the GOC submitted the *Regulation of the Tianjin Harbour Free Trade Zone for Land Administration.* This regulation does not show any preference in providing land-use rights for particular areas within the TPFTZ.

The Department has found that when land is in an industrial park located within the seller's (*e.g.,* county's or municipality's) jurisdiction, the provision of land-use rights is regionally specific under section 771(5A)(D)(iv) of the Act. *See, e.g., Oil Country Tubular Goods From the People's Republic of China: Final Affirmative Countervailing Duty Determination, Final Negative Critical Circumstances Determination,* 74 FR 64045 (December 7, 2009), and accompanying Issues and Decision Memorandum at 20. However, with respect to the land-use rights within the TPFTZ, the jurisdiction of the granting authority does not extend beyond the TPFTZ. As such, the provision of land-use rights under this program is not limited to an enterprise or industry located within a designated geographical region. Therefore, we preliminarily determine that the provision of land-use rights to Tianjin Tianhai within the TPFTZ is not specific under section 771(5A)(D)(iv) of the Act and, thus, this program does not confer a countervailable subsidy.

III. Programs Preliminarily Determined To Be Not Used by Respondents or To Not Provide Benefits During the POI

A. Provision of Welded Tube Steel for LTAR

BTIC reported purchasing welded tube steel, although not for use in the production of subject merchandise. BTIC submitted the amount it purchased in the POI and the price paid, but not the date(s) or terms of the purchase. The GOC did not provide any requested information regarding welded tube steel.

Even under adverse inferences regarding financial contribution, specificity, unsuitability of tier one benchmarks, and the dates and terms of the purchases, we preliminarily determine that this program did not result in a measurable benefit during the POI. Therefore, consistent with CFS Decision Memo at 15, we are not including this subsidy in our calculation.

B. Subsidies Provided in the Tianjin Binhai New Area (''TBNA'') and the Tianjin Economic and Technological Development Area

The GOC and BTIC reported that Tianjin Tianhai received benefits under three programs by virtue of its location in the TBNA. The first is addressed under ''Enterprise Income Tax Rate Reduction in the Tianjin Port Free Trade Zone'' above. The payment to Tianjin Tianhai under the second program, the Energy Saving and Emission Reduction Fund, was less than 0.5 percent of BTIC's sales in the year or receipt, 2009. Therefore, because any potential subsidy would have been expensed prior to the POI in accordance with 19 CFR 351.524(b)(2), we have not analyzed this program further and have not included it our calculations.

Similarly, payments to Tianjin Tianhai under the third program, the Enterprise Development Fund, were less than 0.5 percent of BTIC's sales in the years of receipt, 2008 and 2009. Therefore, because any potential subsidy would have been expensed prior to the POI in accordance with 19 CFR 351.524(b)(2), we have not analyzed this program further and have not included it our calculations.

C. Beijing Industrial Development Fund

BTIC reported receiving grants under this program in 2008 and 2009. Payments to BTIC under this program were less than 0.5 percent of BTIC's sales in the years of receipt, 2008 and 2009. Therefore, because any potential subsidy would have been expensed prior to the POI in accordance with 19 CFR 351.524(b)(2), we have not analyzed this program further and have not included it our calculations.

D. Provision of Land and/or Land Use Rights to SOEs at LTAR

E. Loan and Interest Forgiveness for SOEs

F. The State Key Technology Renovation Project Fund

G. Circular on Issuance of Foreign Trade Development Support Fund

H. Rebates for Export and Credit Insurance Fees

I. GOC and Sub-Central Grants, Loans, and Other Incentives for Development of Famous Brands and China Top World Brands

J. Preferential Lending to Steel Product Producers Under the Ninth Five-Year Plan

K. Treasury Bond Loans

L. Preferential Lending to Steel Cylinders Producers and Exporters Classified as ''Honorable Enterprises''

M. Income Tax Reductions for Export-Oriented FIEs

N. Preferential Tax Programs for FIEs that are Engaged in Research and Development

O. Income Tax Reduction for FIEs that Reinvest Profits in Export-Oriented Enterprises

P. Local Income Tax Exemption and Reduction Programs for ''Productive'' FIEs

Q. Income Tax Credits for Domestically Owned Companies Purchasing Domestically Produced Equipment

R. VAT Refunds for FIEs Purchasing Domestically Produced Equipment

S. VAT Exemptions for Central Region

IV. Programs for Which More Information Is Required

Supplemental questionnaires are outstanding with respect to two programs included in the *Initiation*

Notice: ''Preferential Loans for SOEs'' and ''Provision of Electricity for LTAR.'' Additionally, we intend to seek further information with respect to certain pension grants to Jingcheng Holding identified in recent questionnaire responses. Based on the information we receive, we plan to address these programs in a post-preliminary analysis.

Verification

In accordance with section 782(i)(1) of the Act, we will verify the information submitted by the respondents prior to making our final determination.

Suspension of Liquidation

In accordance with section 703(d)(1)(A)(i) of the Act, we calculated an individual rate for each producer/exporter of the subject merchandise individually investigated. Because only one company was investigated, that company's rate also serves as the All Others rate.

We preliminarily determine the total estimated net countervailable subsidy rates to be:

Exporter/manufacturer	Net subsidy rate
Beijing Tianhai Industry Co., Ltd.; Tianjin Tianhai High Pressure Corp., Ltd.; Langfang Tianhai High Pressure Container Co., Ltd	22.34
All Others	22.34

In accordance with sections 703(d)(1)(B) and (2) of the Act, we are directing U.S. Customs and Border Protection to suspend liquidation of all entries of steel cylinders from the PRC that are entered, or withdrawn from warehouse, for consumption on or after the date of the publication of this notice in the **Federal Register**, and to require a cash deposit or bond for such entries of merchandise in the amounts indicated above.

ITC Notification

In accordance with section 703(f) of the Act, we will notify the ITC of our determination. In addition, we are making available to the ITC all non-privileged and non-proprietary information relating to this investigation. We will allow the ITC access to all privileged and business proprietary information in our files, provided the ITC confirms that it will not disclose such information, either publicly or under an administrative protective order, without the written consent of the Assistant Secretary for Import Administration.

In accordance with section 705(b)(2) of the Act, if our final determination is affirmative, the ITC will make its final determination within 45 days after the Department makes its final determination.

Disclosure and Public Comment

In accordance with 19 CFR 351.224(b), we will disclose to the parties the calculations for this preliminary determination within five days of its announcement. Due to the anticipated timing of verification and issuance of verification reports, case briefs for this investigation must be submitted no later than one week after the issuance of the last verification report. *See* 19 CFR 351.309(c)(i) (for a further discussion of case briefs). Rebuttal briefs must be filed within five days after the deadline for submission of case briefs, pursuant to 19 CFR 351.309(d)(1). A list of authorities relied upon, a table of contents, and an executive summary of issues should accompany any briefs submitted to the Department. Executive summaries should be limited to five pages total, including footnotes. *See* 19 CFR 351.309(c)(2) and (d)(2).

Section 774 of the Act provides that the Department will hold a public hearing to afford interested parties an opportunity to comment on arguments raised in case or rebuttal briefs, provided that such a hearing is requested by an interested party. If a request for a hearing is made in this investigation, the hearing will be held two days after the deadline for submission of the rebuttal briefs, pursuant to 19 CFR 351.310(d), at the U.S. Department of Commerce, 14th Street and Constitution Avenue, N.W., Washington, DC 20230. Parties should confirm by telephone the time, date, and place of the hearing 48 hours before the scheduled time.

Interested parties who wish to request a hearing, or to participate if one is requested, must electronically submit a written request to the Deputy Assistant Secretary for Import Administration using IA ACCESS, within 30 days of the publication of this notice, pursuant to 19 CFR 351.310(c). Requests should contain: (1) The party's name, address, and telephone; (2) the number of participants; and (3) a list of the issues to be discussed. Oral presentations will be limited to issues raised in the briefs. *See id.*

This determination is published pursuant to sections 703(f) and 777(i) of the Act.

Dated: October 11, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

[FR Doc. 2011–26925 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–552–802]

Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Amended Final Results and Final Partial Rescission of Antidumping Duty Administrative Review

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: On September 12, 2011, the Department of Commerce (''Department'') published in the **Federal Register** the final results of the fifth administrative review of the antidumping duty order on certain frozen warmwater shrimp (''shrimp'') from the Socialist Republic of Vietnam (''Vietnam'').[1] The period of review (''POR'') is February 1, 2009, through January 31, 2010. We are amending the *Final Results* to correct certain ministerial errors.

DATES: October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Susan Pulongbarit or Paul Walker, AD/CVD Operations, Office 9, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–4013 or (202) 482–0413, respectively.

SUPPLEMENTARY INFORMATION:

Background

The Department's regulations at 19 CFR 351.224(c)(2) state that a party to an antidumping duty proceeding must file comments concerning ministerial errors within five days after the earlier of the

[1] *See Certain Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Final Results and Final Partial Rescission of Antidumping Duty Administrative Review,* 76 FR 56158 (September 12, 2011) (''*Final Results*'').

date on which the Secretary released disclosure documents to that party or held a disclosure meeting with that party. On September 13, and September 14, 2011, the Department received timely ministerial error allegations from Camimex, Minh Phu Seafood Corporation (and its affiliates Minh Qui Seafood Co., Ltd., and Minh Phat Seafood Co., Ltd.) (collectively ''the Minh Phu Group''), and Viet Foods Co., Ltd. (''Viet Foods'') and its branch Nam Hai Foodstuff Export Company Ltd. (collectively, ''Respondents''). No other party in this proceeding submitted comments on the Department's final margin calculations. Based upon the Department's analysis of the comments and allegations of ministerial errors, the Department has made changes to the margin calculation for Camimex and the Minh Phu Group. The Department also has clarified that in its rescission of Viet Foods in the *Final Results,* the Department inadvertently referred to the company as Viet Hai Foods. Furthermore, as a result of correcting the error in the margin calculation for Camimex, the margins for the companies granted separate rate status were also revised because the margins for those companies were derived from Camimex's and the Minh Phu Group's margins.

Scope of the Order

The scope of the order includes certain warmwater shrimp and prawns, whether frozen, wild-caught (ocean harvested) or farm-raised (produced by aquaculture), head-on or head-off, shell-on or peeled, tail-on or tail-off,[2] deveined or not deveined, cooked or raw, or otherwise processed in frozen form.

The frozen warmwater shrimp and prawn products included in the scope of this order, regardless of definitions in the Harmonized Tariff Schedule of the United States (''HTS''), are products which are processed from warmwater shrimp and prawns through freezing and which are sold in any count size.

The products described above may be processed from any species of warmwater shrimp and prawns. Warmwater shrimp and prawns are generally classified in, but are not limited to, the *Penaeidae* family. Some examples of the farmed and wild-caught warmwater species include, but are not limited to, whiteleg shrimp (*Penaeus vannemei*), banana prawn *(Penaeus merguiensis*), fleshy prawn (*Penaeus chinensis*), giant river prawn (*Macrobrachium rosenbergii*), giant tiger prawn (*Penaeus monodon*), redspotted shrimp *(Penaeus brasiliensis*), southern brown shrimp (*Penaeus subtilis*), southern pink shrimp (*Penaeus notialis*), southern rough shrimp (*Trachypenaeus curvirostris*), southern white shrimp (*Penaeus schmitti*), blue shrimp (*Penaeus stylirostris*), western white shrimp (*Penaeus occidentalis*), and Indian white prawn (*Penaeus indicus*).

Frozen shrimp and prawns that are packed with marinade, spices or sauce are included in the scope of the order. In addition, food preparations (including dusted shrimp), which are not ''prepared meals,'' that contain more than 20 percent by weight of shrimp or prawn are also included in the scope of the order.

Excluded from the scope are: (1) Breaded shrimp and prawns (HTS subheading 1605.20.1020); (2) shrimp and prawns generally classified in the *Pandalidae* family and commonly referred to as coldwater shrimp, in any state of processing; (3) fresh shrimp and prawns whether shell-on or peeled (HTS subheadings 0306.23.0020 and 0306.23.0040); (4) shrimp and prawns in prepared meals (HTS subheading 1605.20.0510); (5) dried shrimp and prawns; (6) canned warmwater shrimp and prawns (HTS subheading 1605.20.1040); and (7) certain battered shrimp. Battered shrimp is a shrimp-based product: (1) That is produced from fresh (or thawed-from-frozen) and peeled shrimp; (2) to which a ''dusting'' layer of rice or wheat flour of at least 95 percent purity has been applied; (3) with the entire surface of the shrimp flesh thoroughly and evenly coated with the flour; (4) with the non-shrimp content of the end product constituting between four and 10 percent of the product's total weight after being dusted, but prior to being frozen; and (5) that is subjected to individually quick frozen (''IQF'') freezing immediately after application of the dusting layer. When dusted in accordance with the definition of dusting above, the battered shrimp product is also coated with a wet viscous layer containing egg and/or milk, and par-fried.

The products covered by the order are currently classified under the following HTS subheadings: 0306.13.0003, 0306.13.0006, 0306.13.0009, 0306.13.0012, 0306.13.0015, 0306.13.0018, 0306.13.0021, 0306.13.0024, 0306.13.0027, 0306.13.0040, 1605.20.1010, and 1605.20.1030. These HTS subheadings are provided for convenience and for customs purposes only and are not dispositive, but rather the written description of the scope of the order is dispositive.

Amended Final Results of the Review

The Act defines ''ministerial error'' as including ''errors in addition, subtraction, or other arithmetic function, clerical errors resulting from inaccurate copying, duplication, or the like, and any other type of unintentional error which the administering authority considers ministerial.'' *See* section 751(h) of the Act. After analyzing Respondents' comments, we have determined, in accordance with section 751(h) of the Act and 19 CFR 351.224(e), that we made certain ministerial errors in our calculations for the final results with respect to Camimex's and the Minh Phu Group's margin calculations and inadvertently referred to Viet Foods as Viet Hai Foods. For a detailed discussion of these ministerial errors, as well as the Department's analysis of these errors, *see* Memorandum to James C. Doyle, through Scot T. Fullerton, from Susan Pulongbarit, regarding ''Fifth Antidumping Administrative Review of Frozen Warmwater Shrimp From the Socialist Republic of Vietnam: Ministerial Error Memorandum,'' dated concurrently with this notice (''Ministerial Errors Memo'').

Because we have revised the rate for Camimex, we are also revising the margin for the companies granted separate-rate status because the margin for those companies was calculated as the weighted average of Camimex's and the Minh Phu Group's margins. In accordance with section 751(h) of the Act, we are amending the final results of the fifth administrative review of certain warmwater shrimp from Vietnam. As a result of correcting the ministerial errors discussed above, we determine that the following dumping margins exist for the period February 1, 2009, through January 30, 2010:

[2] ''Tails'' in this context means the tail fan, which includes the telson and the uropods.

Exporter	Amended final margin (percent)
Camau Frozen Seafood Processing Import Export Corporation (“CAMIMEX”) aka Camimex aka Camau Seafood Factory No. 4 aka Camau Seafood Factory No. 5 aka Camau Frozen Seafood Processing Import & Export aka Camau Frozen Seafood Processing Import Export Corp. (CAMIMEX–FAC 25) aka Frozen Factory No. 4 aka Camau Frozen Seafood Processing Import Export Corporation	0.80
Minh Phu Group: Minh Phat Seafood Co., Ltd. aka Minh Phat Seafood aka Minh Phu Seafood Export Import Corporation (and affiliates Minh Qui Seafood Co., Ltd. and Minh Phat Seafood Co., Ltd.) aka Minh Phu Seafood Corp. aka Minh Phu Seafood Corporation aka Minh Qui Seafood aka Minh Qui Seafood Co., Ltd. aka Minh Phu Seafood Pte aka Minh Phat aka Minh Qui	1.15
Nha Trang Seafoods Group: Nha Trang Seaproduct Company (“Nha Trang Seafoods”) aka Nha Trang Seaproduct Company Nha Trang Seafoods aka Nha Trang Seaproduct Company Nha Trang Seafoods aka NT Seafoods Corporation (“NT Seafoods”) aka Nha Trang Seafoods—F.89 Joint Stock Company (“Nha Trang Seafoods—F.89”) aka NTSF Seafoods Joint Stock Company (“NTSF Seafoods”)	*de minimis*
Amanda Foods (Vietnam) Limited (“Amanda Foods”)	1.03
Bac Lieu Fisheries Joint Stock Company aka Bac Lieu Fisheries Company Limited (“Bac Lieu”) aka Bac Lieu Fisheries Company Limited aka Bac Lieu Fisheries Limited Company aka Bac Lieu Fisheries Company Limited aka Bac Lieu Fis aka Bac Lieu Co. Ltd. aka Bac Lieu Fisheries aka Bac Lieu Fisheries Co. Ltd.	1.03
C.P. Vietnam Livestock Company Limited aka C.P. Vietnam Livestock Corporation (“C.P. Vietnam”) aka C.P. Vietnam Livestock Corporation aka C.P. Vietnam Livestock Co. Ltd. aka CP Livestock	1.03
Cadovimex Seafood Import-Export and Processing Joint Stock Company (“CADOVIMEX–VIETNAM”) aka Cadovimex-Vietnam aka Cai Doi Vam Seafood Import-Export Company (“Cadovimex”) aka Cai Doi Vam Seafood Import-Export Company (Cadovimex) aka Cai Doi Vam Seafood aka Cai Doi Vam Seafood Im-Ex Company (Cadovimex) aka Cai Doi Vam Seafood Processing Factory aka Caidoivam Seafood Company (Cadovimex) aka Caidoivam Seafood Im-Ex Co. aka Cadovimex Seafood Import-Export and Processing Joint Stock Company aka Cai Doi Vam Seafood Import-Export Company aka Cadovimex	1.03
Cafatex Fishery Joint Stock Corporation (“Cafatex Corp.”) aka Cafatex Fishery Joint Stock Corporation (“CAFATEX CORP.”) aka Cantho Animal Fisheries Product Processing Export Enterprise (Cafatex) aka Cafatex aka Cafatex Vietnam aka Xi Nghiep Che Bien Thuy Suc San Xuat Kau Cantho aka Cas aka Cas Branch aka Cafatex Saigon aka Cafatex Fishery Joint Stock Corporation aka Cafatex Corporation aka Taydo Seafood Enterprise aka Cafatex Corp. aka Cafatex Corporation	1.03
Cam Ranh Seafoods Processing Enterprise Pte aka Cam Ranh Seafoods Processing Enterprise Company (“Camranh Seafoods”) aka Camranh Seafoods aka	

Exporter	Amended final margin (percent)
Branch of Camranh Seafoods Processing Enterprise Pte—Quang Ninh Seaproduct Factory aka Quang Ninh Seaproduct Factory (Camranh Seafoods' Branch)	1.03
CATACO Sole Member Limited Liability Company Can Tho Agricultural and Animal Products Import Export Company ("CATACO") aka Can Tho Agricultural and Animal Product Import Export Company ("CATACO") aka Can Tho Agricultural Products aka CATACO aka Can Tho Agricultural and Animal Products Imex Company	1.03
Can Tho Import Export Fishery Limited Company ("CAFISH")	1.03
Coastal Fishery Development aka Coastal Fisheries Development Corporation ("Cofidec") aka Coastal Fisheries Development Corporation (Cofidec) aka COFIDEC aka Coastal Fisheries Development Corporation aka Coastal Fisheries Development Co. aka Coastal Fisheries Development Corp.	1.03
Cuulong Seaproducts Company ("Cuu Long Seapro") aka Cuu Long Seaproducts Limited ("Cuulong Seapro") aka Cuulong Seapro aka Cuulong Seaproducts Company ("Cuulong Seapro") aka Cuu Long Seaproducts Company ("Cuu Long Seapro") aka Cuu Long Seaproducts Company aka Cuu Long Seapro aka Cuulong Seaproducts Company ("Cuu Long Seapro") aka Cuu Long Seaproducts Limited (Cuulong Seapro) aka Cuulong Seapro aka Cuulong Seaproduct Company aka Cuulong Seaproducts Company	1.03
Danang Sea Products Import Export Corporation aka Danang Seaproducts Import Export Corporation ("Seaprodex Danang") aka Danang Seaproducts Import Export Corporation aka Danang Seaproduct Import-Export Corporation aka Danang Seaproducts Import Export aka Tho Quang Seafood Processing & Export Company aka Seaprodex Danang aka Tho Quang Seafood Processing and Export Company aka Tho Quang aka Tho Quang Co.	1.03
Grobest & I-Mei Industrial Vietnam aka Grobest aka Grobest & I-Mei Industrial (Vietnam) Co., Ltd. aka Grobest & I-Mei Industrial (Vietnam) Co., Ltd. ("Grobest") aka Grobest & I-Mei Industry Vietnam	1.03
Investment Commerce Fisheries Corporation ("Incomfish") aka Incomfish aka Investment Commerce Fisheries Corp. aka Incomfish Corp. aka Incomfish Corporation aka Investment Commerce Fisheries aka Investment Commerce Fisheries Corporation aka Incomfish Corporation	1.03
Kim Anh Company Limited ("Kim Anh")	1.03
Minh Hai Export Frozen Seafood Processing Joint Stock Company aka Minh Hai Jostoco aka Minh Hai Export Frozen Seafood Processing Joint-Stock Company ("Minh Hai Jostoco") aka Minh Hai Export Frozen Seafood Processing Joint Stock Company ("Minh Hai Jostoco") aka Minh Hai Export Frozen Seafood Processing Joint-Stock Company aka Minh Hai Joint Stock Seafood Processing Joint-Stock Company aka Minh Hai Export Frozen Seafood Processing Joint-Stock Co., aka Minh-Hai Export Frozen Seafood Processing Joint-Stock Company	1.03
Minh Hai Joint-Stock Seafoods Processing Company ("Seaprodex Minh Hai") aka Sea Minh Hai aka Minh Hai Joint-Stock Seafoods Processing Company aka Seaprodex Minh Hai aka Seaprodex Min Hai aka Seaprodex Minh Hai (Minh Hai Joint Stock Seafoods Processing Co.) aka Seaprodex Minh Hai Factory aka Seaprodex Minh Hai Factory No. 69 aka Seaprodex Minh Hai Workshop 1 aka Seaprodex Minh Hai-Factory No. 78 aka Workshop I Seaprodex Minh Hai	1.03
Minh Hai Sea Products Import Export Company ("Seaprimex Co") aka	

Exporter	Amended final margin (percent)
Minh Hai Sea Products Import Export Company (Seaprimex Co) aka	
Ca Mau Seafood Joint Stock Company (“SEAPRIMEXCO”) aka	
Seaprimexco Vietnam aka	
Seaprimexco aka	
Ca Mau Seafood Joint Stock Company (“Seaprimexco”) aka	
Minh Hai Seaproducts Import Export Corporation aka	
Seaprimexco aka	
Minh Hai Seaproducts Co Ltd. (Seaprimexco) aka	
Ca Mau Seafood Joint Stock Company (“Seaprimexco Vietnam”)	1.03
Ngoc Sinh Private Enterprise aka	
Ngoc Sinh Seafoods aka	
Ngoc Sinh Seafoods Processing and Trading Enterprise aka	
Ngoc Sinh Fisheries aka	
Ngoc Sinh Private Enterprises aka	
Ngoc Sinh Seafoods Processing and Trading Enterprises aka	
Ngoc Sinh aka	
Ngoc Sinh Seafood Processing Company aka	
Ngoc Sinh Seafoods (Private Enterprise)	1.03
Nhat Duc Co., Ltd. aka	
Nhat Duc Co., Ltd. (“Nhat Duc”)	1.03
Nha Trang Fisheries Joint Stock Company (“Nha Trang Fisco”) aka	
Nha Trang Fisheries Joint Stock Company aka	
Nhatrang Fisheries Joint Stock Company aka	
Nha Trang Fisco aka	
Nhatrang Fisco aka	
Nha Trang Fisheries, Joint Stock aka	
Nha Trang Fisheries Joint Stock Company (Nha Trang Fisco)	1.03
Phu Cuong Jostoco Seafood Corporation aka	
Phu Cuong Seafood Processing and Import-Export Co., Ltd. aka	
Phu Cuong Seafood Processing and Import Export Company Limited aka	
Phu Cuong Jostoco Corp.	1.03
Phuong Nam Co., Ltd. (“Phuong Nam”) aka	
Western Seafood Processing and Exporting Factory (“Western Seafood”) aka	
Phuong Nam Foodstuff Corp. aka	
Phuong Nam Co. Ltd.	1.03
Sao Ta Foods Joint Stock Company (“Fimex VN”) aka	
Sao Ta Foods Joint Stock Company aka	
Fimex VN aka	
Sao Ta Seafood Factory aka	
Saota Seafood Factory	1.03
Soc Trang Aquatic Products and General Import Export Company (“Stapimex”) aka	
Soc Trang Seafood Joint Stock Company (“Stapimex”) aka	
Soc Trang Seafood Joint Stock Company aka	
Soc Trang Aquatic Products and General Import Export Company aka	
Stapimex aka	
Soc Trang Aquatic Products and General Import Export Company-(Stapimex) aka	
Stapimex Soc Trans Aquatic Products and General Import Export Company aka	
Stapmex	1.03
Thuan Phuoc Seafoods and Trading Corporation aka	
Thuan Phuoc aka	
Frozen Seafoods Factory No. 32 aka	
Frozen Seafoods Fty aka	
Seafoods and Foodstuff Factory aka	
My Son Seafoods Factory aka	
Seafoods and Foodstuff Factory Vietnam	1.03
UTXI Aquatic Products Processing Company aka	
UT XI Aquatic Products Processing Company aka	
UT–XI Aquatic Products Processing Company aka	
UTXI aka	
UTXI Co. Ltd. aka	
Khanh Loi Seafood Factory aka	
Hoang Phuong Seafood Factory aka	
UTXI Aquatic Products Processing Corporation (“UTXICO”) aka	
UTXI Aquatic Products Processing Corporation aka	
UTXICO	1.03
Viet Hai Seafood Co., Ltd. aka	
Vietnam Fish One Co., Ltd. (“Fish One”) aka	
Viet Hai Seafoods Company Ltd. (“Vietnam Fish One Co. Ltd.”)	1.03
Vietnam-wide Entity	25.76

Assessment

Pursuant to section 751(a)(2)(A) of the Act and 19 CFR 351.212(b), the Department shall determine, and U.S. Customs and Border Protection (''CBP'') shall assess, antidumping duties on all appropriate entries. The Department intends to issue assessment instructions to CBP that are related to the amended final results 15 days after the date of publication of the amended final results of review.

Cash Deposit Requirements

Cash deposit requirements related to the amended final results will be effective retroactively for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the *Final Results,* as provided for by section 751(a)(2)(C) of the Act. The cash deposit rate for companies whose rate was corrected by the amended final results will be the corrected rate for that company noted above. For all Vietnamese exporters of subject merchandise which have not been found to be entitled to a separate rate, the cash deposit rate will be the Vietnam-wide rate of 25.76 percent. For all non-Vietnamese exporters of subject merchandise which have not received their own rate, the cash deposit rate will be the rate applicable to the Vietnamese exporters that supplied that non-Vietnamese exporter. These deposit requirements shall remain in effect until further notice.

These amended final results are published in accordance with sections 751(h) and 777(i)(1) of the Act.

Dated: October 11, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

[FR Doc. 2011–26935 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–583–803]

Light-Walled Welded Rectangular Carbon Steel Tubing From Taiwan: Final Results of the Expedited Sunset Review of the Antidumping Duty Order

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: On July 1, 2011, the Department of Commerce (the Department) initiated the third sunset review of the antidumping duty order on light-walled welded rectangular carbon steel tubing from Taiwan pursuant to section 751(c) of the Tariff Act of 1930, as amended (the Act). The Department has conducted an expedited (120-day) sunset review of this order. As a result of this sunset review, the Department finds that revocation of the antidumping duty order would be likely to lead to continuation or recurrence of dumping as indicated in the ''Final Results of Review'' section of this notice.

DATES: *Effective Date:* October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Jerrold Freeman or Minoo Hatten, AD/CVD Operations, Office 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–0180 or (202) 482–1690, respectively.

SUPPLEMENTARY INFORMATION:

Background

On July 1, 2011, the Department published the notice of initiation of the sunset review of the antidumping duty order [1] on light-walled welded rectangular carbon steel tubing from Taiwan pursuant to section 751(c) of the Act. *See Initiation of Five-Year (''Sunset'') Review,* 76 FR 38613 (July 1, 2011) (*Notice of Initiation*).

The Department received a notice of intent to participate in this sunset review from the domestic interested parties, Allied Tube and Conduit, Bull Moose Tube, California Steel and Tube, Hannibal Industries, JMC Steel Group, Leavitt Tube, Searing Industries, and Western Tube and Conduit (collectively the domestic interested parties), within the 15-day period specified in 19 CFR 351.218(d)(1)(i). The domestic interested parties claimed interested-party status under section 771(9)(C) of the Act as manufacturers and/or producers of a domestic like product in the United States.

The Department received a complete substantive response to the *Notice of Initiation* from the domestic interested parties within the 30-day period specified in 19 CFR 351.218(d)(3)(i). The Department received no substantive response from any respondent interested parties. In accordance with section 751(c)(3)(B) of the Act and 19 CFR 351.218(e)(1)(ii)(C)(2), the Department is conducting an expedited (120-day) sunset review of the antidumping duty order on light-walled welded rectangular carbon steel tubing from Taiwan.

Scope of the Order

The product covered by the order is light-walled welded carbon steel pipe and tube of rectangular (including square) cross-section having a wall thickness of less than 0.156 inch. This merchandise is classified under item number 7306.61.5000 of the Harmonized Tariff Schedule (HTS). It was formerly classified under item number 7306.60.5000. The HTS item numbers are provided for convenience and customs purposes only. The written product description remains dispositive.

Analysis of Comments Received

All issues raised in this review are addressed in the ''Issues and Decision Memorandum for the Expedited Sunset Review of the Antidumping Duty Order on Light-Walled Welded Rectangular Carbon Steel Tubing From Taiwan'' to Deputy Assistant Secretary for Import Administration Ronald K. Lorentzen from Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations Christian Marsh dated concurrently with this notice (Issues and Decision Memo), which is hereby adopted by this notice. The issues discussed in the Issues and Decision Memo include the likelihood of continuation or recurrence of dumping and the magnitude of the margin of dumping likely to prevail if the order were revoked. Parties can find a complete discussion of all issues raised in this review and the corresponding recommendations in this public memorandum which is on file in the Central Records Unit, room 7046 of the main Department of Commerce building.

In addition, a complete version of the Issues and Decision Memo can be accessed directly on the Web at *http://ia.ita.doc.gov/frn.* The paper copy and electronic version of the Issues and Decision Memo are identical in content.

Final Results of Review

The Department determines that revocation of the antidumping duty order on light-walled welded rectangular carbon steel tubing from Taiwan would be likely to lead to continuation or recurrence of dumping at the following weighted-average percentage margins:

[1] *Antidumping Duty Order; Light-Walled Welded Rectangular Carbon Steel Tubing From Taiwan,* 54 FR 12467 (March 27, 1989).

Company	Weighted-Average Margin (Percent)
Ornatube Enterprise	5.51
Vulcan Industrial Corp.	40.97
Yieh Hsing Industries, Ltd	40.97
All other manufacturers/producers/exporters	29.15

Notification Regarding APO

This notice serves as a reminder to parties subject to administrative protective order (APO) of their responsibility concerning the disposition of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a). Timely written notification of the destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

The Department is issuing and publishing the final results and notice in accordance with sections 751(c), 752(c), and 777(i)(1) of the Act.

Dated: October 11, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

[FR Doc. 2011–26937 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–570–971]

Multilayered Wood Flooring From the People's Republic of China: Final Affirmative Countervailing Duty Determination

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (''Department'') has determined that countervailable subsidies are being provided to producers and exporters of multilayered wood flooring (''wood flooring'') from the People's Republic of China (''PRC''). For information on the subsidy rates, *see* the ''Suspension of Liquidation'' section of this notice.

DATES: *Effective Date:* October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Shane Subler or Joshua Morris, AD/CVD Operations, Office 1, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–0189 and (202) 482–1779, respectively.

SUPPLEMENTARY INFORMATION:

Period of Investigation

The period for which we are measuring subsidies, or period of investigation (''POI''), is January 1, 2009, through December 31, 2009.

Case History

The following events have occurred since our *Preliminary Determination. See Multilayered Wood Flooring From the People's Republic of China: Preliminary Affirmative Countervailing Duty Determination,* 76 FR 19034 (April 6, 2011) (''*Preliminary Determination*'').

From March 24, 2011, through April 15, 2011, the Department received ministerial error allegations regarding certain companies that received adverse-facts available (''AFA'') in the *Preliminary Determination:* (1) Guangzhou Pan Yu Kang Da Board Co., Ltd. and Kornbest Enterprises Ltd.; (2) Baroque Timber Industries (Zhongshan) Co., Ltd., Riverside Plywood Corporation, Samling Elegant Living Trading (Labuan) Ltd., Samling Global USA, Ind., Samling Riverside Co., Ltd., and Suzhou Times Flooring Co., Ltd. (collectively, the ''Samling Group''); (3) Shanghai Eswell Timber Co., Ltd. (''Eswell Timber''); (4) UA Wood Floors, Inc.; and (5) Shenzhenshi Huanwei Woods Co., Ltd.

On April 21, 2011, the Department released a memorandum addressing these allegations. *See* Memorandum to Gary Taverman, ''Ministerial Error Allegations Regarding the AFA Company List,'' (April 21, 2011) (''Prelim Ministerial Error Memo''), available in the Department's Central Records Unit (''CRU'') in Room 7046 of the main Department building. In the Prelim Ministerial Error Memo, the Department stated that the allegations did not constitute ministerial errors under 19 CFR 351.224(f) and (g), but in order to confirm the claims of the interested parties, we would request additional information from the parties and address this information in the final determination.

On June 24, 2011, we issued questionnaires to the parties addressed in the Prelim Ministerial Error Memo. On June 30, 2011, and July 1, 2011, we received responses from these parties, with one party withdrawing its request to amend the *Preliminary Determination.* For a complete discussion of the parties' submissions and the Department's position, *see* Memorandum from Christian Marsh, ''Issues and Decision Memorandum for the Final Determination in the Countervailing Duty Investigation of Multilayered Wood Flooring from the People's Republic of China'' (October 11, 2011) (hereafter, ''Issues and Decision Memorandum''), which is hereby adopted by this notice.

On March 28, 2011, the Government of the PRC (''GOC'') submitted a response to the supplemental questionnaire issued to it on March 14, 2011, shortly before the *Preliminary Determination.* On May 3, 2011, the GOC placed additional factual information on the record.

The Department issued supplemental questionnaires to Fine Furniture (Shanghai) Ltd., Great Wood (Tonghua) Ltd., and Fine Furniture Plantation (Shishou) Ltd. (collectively, ''Fine Furniture''), Zhejiang Layo Wood Industry Co., Ltd. and Jiaxing Brilliant Import & Export Co., Ltd. (collectively, ''Layo''), and Zhejiang Yuhua Timber Co., Ltd. (''Yuhua'') on May 4, 2011, and received responses on May 13, 2011. On May 4, 2011, the Department also issued a supplemental questionnaire to the GOC. On May 9, 2011, the Department issued a letter to the GOC regarding the May 4, 2011, supplemental questionnaire, to which the GOC declined to respond, as stated in the GOC's letter of May 20, 2011.

On May 9, 2011, the Department aligned the final determination in this countervailing duty (''CVD'') investigation of wood flooring from the PRC with the final determination in the companion antidumping duty (''AD'') investigation. *See Multilayered Wood Flooring From the People's Republic of China: Alignment of Final Countervailing Duty Determination With Final Antidumping Duty Determination,* 76 FR 26685 (May 9, 2011).

From June 3, 2011, through June 14, 2011, the Department conducted verifications of the questionnaire responses submitted by Fine Furniture, Layo, and Yuhua. *See* Memorandum to Susan H. Kuhbach, ''Verification Report: Fine Furniture (Shanghai) Ltd. (''FF Shanghai''), Great Wood (Tonghua) Ltd. (''Great Wood''), and FF Plantation (Shishou) Limited (''FFPS'')

(collectively, ''Fine Furniture''),'' (July 6, 2011); *see also* Memorandum to Susan H. Kuhbach, ''Verification Report: Zhejiang Layo Wood Industry Co., Ltd. (''Layo Wood'') and Jiaxing Brilliant Import & Export Co., Ltd. (''Brilliant'') (collectively, ''Layo''),'' (July 6, 2011); and Memorandum to Susan H. Kuhbach, ''Verification Report: Zhejiang Yuhua Timber Co., Ltd. (''Yuhua''),'' (July 13, 2011), available in the CRU.

On July 27, 2011, the Department released its post-preliminary analyses for Fine Furniture, Layo, and Yuhua. *See* Memorandum to Ronald K. Lorentzen, ''Countervailing Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Post-Preliminary Analysis Memorandum for Fine Furniture (Shanghai) Ltd., Great Wood (Tonghua) Ltd., and Fine Furniture Plantation (Shishou) Ltd. (collectively, ''Fine Furniture''),'' dated July 22, 2011; Memorandum to Ronald K. Lorentzen, Deputy Assistant Secretary for Import Administration, through Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, from Susan H. Kuhbach, Office Director AD/CVD Operations, Office 1, ''Countervailing Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Post-Preliminary Analysis Memorandum for Zhejiang Layo Wood Industry Co., Ltd. and Jiaxing Brilliant Import & Export Co., Ltd. (collectively, ''Layo''),'' (July 22, 2011); and Memorandum to Ronald K. Lorentzen, ''Countervailing Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Post-Preliminary Analysis Memorandum for Zhejiang Yuhua Timber Co., Ltd. (''Yuhua''),'' (July 22, 2011), available in the CRU.

We received case briefs from the GOC; Fine Furniture; Yuhua; Shanghai Lizhong Wood Products Co., Ltd./The Lizhong Wood Industry Limited Company of Shanghai; Chinafloors Timber (China) Co., Ltd. (''Chinafloors''); Samling Group; Eswell Timber and Vicwood Industry (Suzhou) Co., Ltd.; Style Limited; and the Coalition for American Hardwood Parity (''Petitioner'') on August 3, 2011. The GOC, Fine Furniture, Chinafloors, Style Limited, and Petitioner submitted rebuttal briefs on August 8, 2011.

We conducted a public hearing on September 8, 2011, at the request of the GOC, Fine Furniture, and Layo.

Scope of the Investigation

Multilayered wood flooring is composed of an assembly of two or more layers or plies of wood veneer(s) [1] in combination with a core. The several layers, along with the core, are glued or otherwise bonded together to form a final assembled product. Multilayered wood flooring is often referred to by other terms, *e.g.,* ''engineered wood flooring'' or ''plywood flooring.'' Regardless of the particular terminology, all products that meet the description set forth herein are intended for inclusion within the definition of subject merchandise.

All multilayered wood flooring is included within the definition of subject merchandise, without regard to: dimension (overall thickness, thickness of face ply, thickness of back ply, thickness of core, and thickness of inner plies; width; and length); wood species used for the face, back and inner veneers; core composition; and face grade. Multilayered wood flooring included within the definition of subject merchandise may be unfinished (*i.e.,* without a finally finished surface to protect the face veneer from wear and tear) or ''prefinished'' (*i.e.,* a coating applied to the face veneer, including, but not exclusively, oil or oil-modified or water-based polyurethanes, ultra-violet light cured polyurethanes, wax, epoxy-ester finishes, moisture-cured urethanes and acid-curing formaldehyde finishes.) The veneers may be also soaked in an acrylic-impregnated finish. All multilayered wood flooring is included within the definition of subject merchandise regardless of whether the face (or back) of the product is smooth, wire brushed, distressed by any method or multiple methods, or hand-scraped. In addition, all multilayered wood flooring is included within the definition of subject merchandise regardless of whether or not it is manufactured with any interlocking or connecting mechanism (for example, tongue-and-groove construction or locking joints). All multilayered wood flooring is included within the definition of the subject merchandise regardless of whether the product meets a particular industry or similar standard.

The core of multilayered wood flooring may be composed of a range of materials, including but not limited to hardwood or softwood veneer, particleboard, medium-density fiberboard, high-density fiberboard (''HDF''), stone and/or plastic composite, or strips of lumber placed edge-to-edge.

[1] A ''veneer'' is a thin slice of wood, rotary cut, sliced or sawed from a log, bolt or flitch. Veneer is referred to as a ply when assembled.

Multilayered wood flooring products generally, but not exclusively, may be in the form of a strip, plank, or other geometrical patterns (*e.g.,* circular, hexagonal). All multilayered wood flooring products are included within this definition regardless of the actual or nominal dimensions or form of the product.

Specifically excluded from the scope are cork flooring and bamboo flooring, regardless of whether any of the sub-surface layers of either flooring are made from wood. Also excluded is laminate flooring. Laminate flooring consists of a top wear layer sheet not made of wood, a decorative paper layer, a core-layer of HDF, and a stabilizing bottom layer.

Imports of the subject merchandise are provided for under the following subheadings of the Harmonized Tariff Schedule of the United States (''HTSUS''): 4412.31.0520; 4412.31.0540; 4412.31.0560; 4412.31.2510; 4412.31.2520; 4412.31.4040; 4412.31.4050; 4412.31.4060; 4412.31.4070; 4412.31.5125; 4412.31.5135; 4412.31.5155; 4412.31.5165; 4412.31.3175; 4412.31.6000; 4412.31.9100; 4412.32.0520; 4412.32.0540; 4412.32.0560; 4412.32.2510; 4412.32.2520; 4412.32.3125; 4412.32.3135; 4412.32.3155; 4412.32.3165; 4412.32.3175; 4412.32.3185; 4412.32.5600; 4412.39.1000; 4412.39.3000; 4412.39.4011; 4412.39.4012; 4412.39.4019; 4412.39.4031; 4412.39.4032; 4412.39.4039; 4412.39.4051; 4412.39.4052; 4412.39.4059; 4412.39.4061; 4412.39.4062; 4412.39.4069; 4412.39.5010; 4412.39.5030; 4412.39.5050; 4412.94.1030; 4412.94.1050; 4412.94.3105; 4412.94.3111; 4412.94.3121; 4412.94.3131; 4412.94.3141; 4412.94.3160; 4412.94.3171; 4412.94.4100; 4412.94.5100; 4412.94.6000; 4412.94.7000; 4412.94.8000; 4412.94.9000; 4412.94.9500; 4412.99.0600; 4412.99.1020; 4412.99.1030; 4412.99.1040; 4412.99.3110; 4412.99.3120; 4412.99.3130; 4412.99.3140; 4412.99.3150; 4412.99.3160; 4412.99.3170; 4412.99.4100; 4412.99.5100; 4412.99.5710; 4412.99.6000; 4412.99.7000; 4412.99.8000; 4412.99.9000; 4412.99.9500; 4418.71.2000; 4418.71.9000; 4418.72.2000; and 4418.72.9500.

While HTSUS subheadings are provided for convenience and customs

purposes, the written description of the subject merchandise is dispositive.

Scope Comments

Following the *Preliminary Determination,* on May 19, 2011, the Department issued a decision memorandum addressing multiple scope issues in this and the concurrent AD investigation of wood flooring from the PRC. *See* Memorandum to Christian Marsh, ''Scope'' (May 19, 2011) (''Scope Memo''); *see also Multilayered Wood Flooring From the People's Republic of China: Preliminary Determination of Sales at Less Than Fair Value* 76 FR 30656 (May 26, 2011). We sought comments on the scope in both the AD and CVD cases. *See* Letter to All Interested Parties from Nancy Decker, Program Manager, Office 1, AD/CVD Operations, Import Administration, ''RE: Antidumping and Countervailing Duty Investigations: *Multilayered Wood Flooring from the People's Republic of China,*'' (May 25, 2011).

In response, interested parties filed scope-related comments in submissions on June 6, 2011, June 14, 2011, and June 15, 2011, as well as in case briefs on August 3, 2011, and rebuttal briefs on August 8, 2011, and August 9, 2011. Additionally, a scope-related submission was received the same day the Scope Memo was released and, therefore, was not analyzed in the Scope Memo, but is addressed in this final determination. Based on our analysis of all the comments, we have changed the scope to eliminate references to certain HTSUS numbers. For a complete discussion of this change, as well as a summary of the parties' comments and the Department's positions, *see* the Issues and Decision Memorandum.

Injury Test

On December 17, 2010, the U.S. International Trade Commission (''ITC'') published its affirmative preliminary determination that there is a reasonable indication that an industry in the United States is materially injured by reason of allegedly subsidized imports of wood flooring from the PRC. *See Multilayered Wood Flooring From China,* 75 FR 79019 (December 17, 2010).

Analysis of Comments Received

All issues raised in the case and rebuttal briefs by parties to this investigation are addressed in the Issues and Decision Memorandum. A list of the issues raised is attached to this notice as Appendix I. The Issues and Decision Memorandum is a public document and is on file electronically via Import Administration's Antidumping and Countervailing Duty Centralized Electronic Service System (''IA ACCESS''). Access to IA ACCESS is available in the CRU. In addition, a complete version of the Issues and Decision Memorandum can be accessed directly on the internet at *http://www.trade.gov/ia/*. The signed Issues and Decision Memorandum and the electronic versions of the Issues and Decision Memorandum are identical in content.

Use of Adverse Facts Available

For purposes of this final determination, we have continued to rely on facts available and have continued to use adverse inferences in accordance with sections 776(a) and (b) of the Tariff Act of 1930, as amended (''Act'') with regard to 1) the GOC's provision of electricity for less than adequate remuneration, and 2) the countervailable subsidy rates for the non-cooperative companies that did not respond to the Department's quantity and value (''Q&V'') questionnaire. In a departure from the *Preliminary Determination,* we are now applying AFA to 124 companies instead of 127 companies. A full discussion of this change and our decision to apply AFA is presented in the Issues and Decision Memorandum under the section ''Use of Facts Otherwise Available and Adverse Inferences.''

Suspension of Liquidation

In accordance with section 703(d)(1)(A)(i) of the Act, we have calculated a rate for each individually investigated producer/exporter of the subject merchandise. Section 705(c)(5)(A)(i) of the Act states that for companies not investigated, we will determine an ''all-others'' rate equal to the weighted average countervailable subsidy rates established for exporters and producers individually investigated, excluding any zero and *de minimis* countervailable subsidy rates, and any rates determined entirely under section 776 of the Act.

In this investigation, two of the individually examined companies received rates of *de minimis.* Fine Furniture received an above-*de minimis* rate. Therefore, we have assigned the rate calculated for Fine Furniture to ''all-others.'' Finally, for the non-cooperative companies that did not respond to our Q&V questionnaire, we have calculated rates based solely on facts available with an adverse inference, in accordance with sections 776(a) and (b) of the Act. *See* ''Non-Cooperative Companies'' section of the Issues and Decision Memorandum.

We determine the total net countervailable subsidy rates to be:

Exporter/Manufacturer	Net subsidy rate
Fine Furniture (Shanghai) Ltd.; Great Wood (Tonghua) Ltd.; Fine Furniture Plantation (Shishou) Ltd	1.50
Zhejiang Layo Wood Industry Co., Ltd.; Jiaxing Brilliant Import & Export Co., Ltd	** 0.33
Zhejiang Yuhua Timber Co., Ltd	** 0.47
9 Miles Oak Flooring (China) *	26.73
Anhui HUPO Wood Industry Co., Ltd. *	26.73
Anji Tianpeng Bamboo & Wooden Floor Co., Ltd. *	26.73
Anlian Wood Co., Ltd. *	26.73
Beijing Forever Strong Construction & Decoration Material Co., Ltd. *	26.73
Beijing New Building Material (Group) Co., Ltd. *	26.73
Beijing W.A Wood Co., Ltd. *	26.73
Cairun Floor Building Material Co., Ltd. *	26.73
Changchun Zhongyi Wood Co., Ltd. *	26.73
Changzhou Credit International Trade Co., Ltd. *	26.73
Changzhou Green Spot Wood Industry Co., Ltd. *	26.73
Changzhou Jiahao Wood Trade Co., Ltd. *	26.73
Changzhou Leili Wood Industry Co., Ltd. *	26.73
Changzhou OPLS Decoration Materials Co., Ltd. *	26.73
Chaohu Great Mainland Flooring Co., Ltd. *	26.73
Chaohu Vgreen Timber Co., Ltd. *	26.73
China Xuzhou Tengmao Wood Co., Ltd. *	26.73

Exporter/Manufacturer	Net subsidy rate
Chuangfu Wood Flooring Cld., Co.*	26.73
Complete Flooring Supply Corporation*	26.73
Dalian Brilliant Future International Trade Co., Ltd.*	26.73
Dalian Hongjia Imp. & Exp. Co., Ltd.*	26.73
Dalian Luming Group*	26.73
Dalian Maruni Wood Works Co., Ltd.*	26.73
Dalian Ontime International Trade Co.*	26.73
Dalian Taiyangshi International Trading Co., Ltd.*	26.73
Dalian Turuss Wood Industry Co., Ltd.*	26.73
Dongguan Forest Century Wooden Co., Ltd.*	26.73
Elegant Living Corporation*	26.73
Foshan Linguan Wood Products Co., Ltd.*	26.73
Foshan Pengbang Wood Manufacturer Co., Ltd.*	26.73
Foshan Shunde Hechengchuangzhan Wood Co., Ltd.*	26.73
Foshan Tocho Timber Co., Ltd.*	26.73
Fujian Jianou Huayu Bamboo Industry Co., Ltd.*	26.73
Fuzhou Floors China Co., Ltd.*	26.73
Gao'an City Kangli Bamboo And Wooden Products Co., Ltd.*	26.73
Giant Flooring*	26.73
Glassical Industrial Limited*	26.73
Great Forest Wood Limited*	26.73
Green Elf Flooring (also dba Hong Ding Lumber Co.)*	26.73
Guangdong Guangyang Hi-Tech Industry Co., Ltd.*	26.73
Guangdong Yingran Wood Industry*	26.73
Guangzhou Fnen Wood Flooring*	26.73
Guangzhou Homewell Trade Co., Ltd.*	26.73
Guangzhou Quanfeng Wood Industry Co., Ltd.*	26.73
Handan Global Wood Limited*	26.73
Hangzhou Dazhuang Floor Co.*	26.73
Hangzhou Fuyang Zhongjian Wood Industry Co., Ltd.*	26.73
Hangzhou Kingdom Imp & Exp Trading Corp., Ltd.*	26.73
Hangzhou Singular Group Co., Ltd.*	26.73
Hangzhou Tianlin Industrial Co., Ltd.*	26.73
Heze Lv Sen Wood Co., Ltd.*	26.73
Homewell (Xiamen) Industry Co., Ltd.*	26.73
Huidong Weikang Rubber & Plastic Products Co., Ltd.*	26.73
HU'Made Group*	26.73
Huzhou Boge Import And Export Co., Ltd.*	26.73
Huzhou Jinjie Industrial Co., Ltd.*	26.73
Huzhou Natural Forest Flooring Co., Ltd.*	26.73
Huzhou Tianlong Wood Co., Ltd.*	26.73
Huzhou Top Wood Co., Ltd.*	26.73
Huzhou Yaxin Arts & Crafts Co., Ltd.*	26.73
Jiangmen Xinhui Yinhu Woodwork Co., Ltd.*	26.73
Jiangsu Happy Wood Industrial Group Co., Ltd.*	26.73
Jiangsu Horizon Trade Co., Ltd.*	26.73
Jiangsu Kentier Wood Co., Ltd.*	26.73
Jiangsu Nanyang Wood Co., Ltd.*	26.73
Jiangsu Wanli Wooden Co., Ltd.*	26.73
Jiangxi Kangtilong Bamboo Products Co., Ltd.*	26.73
Jiashan Greenland International Trading Co., Ltd.*	26.73
Jiashan Huayu Lumber Co., Ltd.*	26.73
Jiashan Longsen Lumbering Co., Ltd.*	26.73
Jiashan On-Line Lumber Co., Ltd.*	26.73
Jiaxing Hengtong Wood Co., Ltd.*	26.73
Jilin Newco Wood Industries Co., Ltd.*	26.73
Jining Sensen Wood Industry Co., Ltd.*	26.73
Jining Sunny Wood Co., Ltd.*	26.73
Kingswood Timber*	26.73
Kornbest Enterprises Ltd.*	26.73
Lianyungang Shuntian Timber Co., Ltd.*	26.73
Longeron I&E Co., Ltd.*	26.73
Lord Parquet Industry Co., Limited.*	26.73
Lyowood Industrial Co., Ltd.*	26.73
MacDouglas Wood Flooring (Suzhou) Co., Ltd.*	26.73
Nanjing Dimac Wood Industry Co., Ltd.*	26.73
Qiaosen Wood Flooring Industry Company*	26.73
Qichuang Wood Industrial Co., Ltd.*	26.73
Qingdao Fuguichao Wood Co., Ltd.*	26.73
Quanfa Woodwork (Shenzhen) Co., Ltd.*	26.73
Shandong Fuma Commerce & Trade Co., Ltd.*	26.73
Shandong Yuncheng Jinyang Wood Industry Co., Ltd.*	26.73
Shanghai Chunna Industrial Co., Ltd.*	26.73

Exporter/Manufacturer	Net subsidy rate
Shanghai Eswell Enterprise Co., Ltd.*	26.73
Shanghai Feihong Wood Products Co.*	26.73
Shanghai Guangri Flooring Co., Ltd.*	26.73
Shanghai Pinsheng Wood Industry Co., Ltd.*	26.73
Shanghai Pujiang United Wood Co., Ltd.*	26.73
Shanghai Yiming Wooden Industry Co., Ltd.*	26.73
Shenyang Bask Industry Co., Ltd.*	26.73
Shenzhen JianYuanXin Trade Co., Ltd.*	26.73
Shuanghai Shuai Yuan Wood Industry Co., Ltd.*	26.73
Sterling Pacific Wood Products Co., Ltd.*	26.73
Suifenhe Sanmulin Economic and Trade Co., Ltd.*	26.73
Suzhou Duolun Wood Industry Co., Ltd.*	26.73
Tengmao Wood Co., Ltd.*	26.73
Tianjin Zeyuan Wood Industry Co., Ltd.*	26.73
Twowins Bamboo & Wood Products Co., Ltd.*	26.73
Weifang Jiayuan Imp & Exp Co., Ltd.*	26.73
Wenzhou Timber Group Company*	26.73
Wuhan Nanhong Materials & Goods Fitting Co., Ltd.*	26.73
Wuxi Haisen Decorates Material Co., Ltd.*	26.73
Xiamen Homeshining Industry Co., Ltd.*	26.73
Xuzhou Fuxiang Wood Co., Ltd.*	26.73
Xuzhou Huanqiu Import & Export Trade Co., Ltd.*	26.73
Xuzhou Tengmao Wood Co., Ltd.*	26.73
Xuzhou Yijia Manufacture Co., Ltd.*	26.73
Xuzhou Yijia Wood Manufacture Co., Ltd.*	26.73
Yinlong Wood Products Co., Ltd.*	26.73
Ys Nature International Trading Co., Ltd.*	26.73
Zhejiang Assun Wood Co., Ltd.*	26.73
Zhejiang Gaopai Wood Co., Ltd.*	26.73
Zhejiang Huayue Wooden Products Co., Ltd.*	26.73
Zhejiang Yongji Wooden Co., Ltd.*	26.73
Zhejiang Yongyu Bamboo Development*	26.73
Zhongshan New Oasis Wood Industry Co., Ltd.*	26.73
Zhongyi Bamboo Industrial Co., Ltd. Fujian*	26.73
All-Others	1.50

* Non-cooperative company receiving the AFA rate.
** (*de minimis*).

Also, in accordance with section 703(d) of the Act, we instructed U.S. Customs and Border Protection (''CBP'') to discontinue the suspension of liquidation for CVD purposes for subject merchandise entered on or after August 4, 2011, but to continue the suspension of liquidation as previously ordered for entries made from April 6, 2011, through August 3, 2011.

If the ITC issues a final affirmative injury determination we will issue a CVD order, and we will require a cash deposit of estimated countervailing duties for such entries of merchandise in the amounts indicated above. Because Layo and Yuhua were found to receive *de minimis* subsidies, they would be excluded from the CVD order. If the ITC determines that material injury, or threat of material injury, does not exist, this proceeding will be terminated and all estimated deposits or securities posted as a result of the suspension of liquidation will be refunded or canceled.

ITC Notification

In accordance with section 705(d) of the Act, we will notify the ITC of our determination. In addition, we are making available to the ITC all non-privileged and non-proprietary information related to this investigation. We will allow the ITC access to all privileged and business proprietary information in our files, provided the ITC confirms that it will not disclose such information, either publicly or under an administrative protective order (''APO''), without the written consent of the Assistant Secretary for Import Administration.

Return or Destruction of Proprietary Information

In the event that the ITC issues a final negative injury determination, this notice will serve as the only reminder to parties subject to an APO of their responsibility concerning the destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return/destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

This determination is issued pursuant to sections 705(d) and 777(i) of the Act.

Dated: October 11, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

Appendix I

List of Comments and in the Issues and Decision Memorandum

General Issues

Comment 1 Application of the CVD Law to the PRC and Double Counting
Comment 2 Whether Application of the CVD Law to NMEs Violates the APA
Comment 3 Requests for Information Regarding Other Programs
Comment 4 Provision of Electricity for Less Than Adequate Remuneration
Comment 5 Application of AFA to Non-Cooperative Respondents
Comment 6 Removal of Companies in the List of AFA Companies
Comment 7 ''All-Others'' Rate Calculation

Scope-Related Issues

Comment 8 Exclusion Requests for Plywood Panels or Veneer
Comment 9 Strand-Woven Lignocellulosic Flooring
Comment 10 Scope Language Regarding HTSUS Subheadings
Comment 11 Continued Requests for Certain Exclusions

[FR Doc. 2011–26892 Filed 10–17–11; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–970]

Multilayered Wood Flooring From the People's Republic of China: Final Determination of Sales at Less Than Fair Value

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

DATES: *Effective Date:* October 18, 2011.

SUMMARY: On May 26, 2011, the Department of Commerce (''Department'') published its preliminary determination of sales at less than fair value (''LTFV'') in the antidumping investigation of multilayered wood flooring from the People's Republic of China (''PRC'').[1] On June 27, 2011, the Department published its amended preliminary determination of sales at LTFV in the antidumping investigation of multilayered wood flooring from the PRC.[2] The Department invited interested parties to comment on the *Preliminary Determination.* Based on the Department's analysis of the comments received, the Department has made changes from the *Preliminary Determination.* The Department determines that multilayered wood flooring from the PRC is being, or is likely to be, sold in the United States at LTFV, as provided in section 735 of the Tariff Act of 1930, as amended (the ''Act''). The final dumping margins for this investigation are listed in the ''Final Determination'' section below.

FOR FURTHER INFORMATION CONTACT: Charles Riggle, John Hollwitz, Brandon Petelin or Erin Kearney, AD/CVD Operations, Office 4, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–0650, (202) 482–2336, (202) 482–8173 or (202) 482–0167, respectively.

SUPPLEMENTARY INFORMATION:

Background

The Department published its *Preliminary Determination* of sales at LTFV and postponement of the final determination on May 26, 2011. On May 31, 2011, Riverside Plywood Corporation, Samling Elegant Living Trading (Labuan) Limited, Baroque Timber Industries (Zhongshan) Co. Ltd., Samling Global USA, Inc., Samling Riverside Co., Ltd. and Suzhou Times Flooring Co., Ltd.(collectively, the ''Samling Group'') and Vicwood Industry (Suzhou) Co., Ltd. (''Vicwood'') submitted timely ministerial error allegations. The Department published its *Amended Preliminary Determination* of sales at LTFV on June 27, 2011. Following the release of *Amended Preliminary Determination,* on June 23, 2011, Shanghai Lizhong Wood Products Co., Ltd. (''Lizhong'') filed a submission requesting to correct Shanghai Lizhong Wood Products Co., Ltd.'s name as specified in its Separate Rate Application, or at minimum to instruct U.S Customs and Border Protection (''CBP'') of the correct name for Lizhong. *See* Separate Rate section below.

Between June 2, 2011 and July 1, 2011, the Department conducted verification of mandatory respondents Zhejiang Yuhua Timber Co., Ltd. (''Yuhua''), Zhejiang Layo Wood Industry Co., Ltd. (''Layo Wood''), and the Samling Group.[3] On July 6, 2011, the Department received a supplemental questionnaire response from Vicwood.

The Coalition for American Hardwood Parity (''Petitioner''), Style Limited, Shanghai Lizhong Wood Products Co., Ltd/The Lizhong Wood Industry Limited Company of Shanghai (''Lizhong''), Lumber Liquidators Services, LLC (''Lumber Liquidators''), Home Legend LLC (''Home Legend''), Armstrong Wood Products (Kunshan) Co., Ltd. (''Armstrong Kunshan''), Fine Furniture (Shanghai) Limited (''Fine Furniture''), Chinafloors Timber (China) Co., Ltd. (''Chinafloors''), the Government of the People's Republic of China (''GOC''), Yuhua, Samling Group, and Layo Wood submitted case briefs on August 4, 2011. On August 9, 2011, Petitioner, Style Limited, Lumber Liquidators, Home Legend, Armstrong Kunshan, Fine Furniture, Yuhua, Samling Group, and Layo Wood filed rebuttal briefs. In addition, on August 15, 2011, respondent Layo Wood resubmitted its August 4, 2011 case brief.[4] The Department conducted a public hearing on August 24, 2011.

Period of Investigation

The period of investigation (''POI'') is April 1, 2010, through September 30, 2010. This period corresponds to the two most recent fiscal quarters prior to the month of the filing of the petition, which was October 2010.[5]

Analysis of Comments Received

All issues raised in the case and rebuttal briefs by parties to this investigation, as well as comments received pursuant to the Department's requests are addressed in the Issues and Decisions Memorandum.[6] A list of the issues which the parties raised and to which the Department responds in the Issues and Decision Memorandum is attached to this notice as Appendix I. The Issues and Decision Memorandum is a public document and is on file electronically via Import Administration's Antidumping and Countervailing Duty Centralized Electronic Service System (IA ACCESS). Access to IA ACCESS is available in the Central Records Unit (CRU), room 7046 of the main Department of Commerce building. In addition, a complete version of the Issues and Decision Memorandum can be accessed directly on the Internet at *http://www.trade.gov/ia/.* The signed Issues and Decision Memorandum and the electronic versions of the Issues and Decision Memorandum are identical in content.

Changes Since the Preliminary Determination

Changes Applicable to Multiple Companies

1. The Department changed the surrogate value (''SV'') of non-coniferous, non-tropical core veneer inputs from Philippine Harmonized Tariff Schedule (''HTS'') 4408.90.10 to Philippine HTS 4408.90.90.[7]

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[1] *See Multilayered Wood Flooring from the People's Republic of China: Preliminary Determination of Sales at Less Than Fair Value,* 76 FR 30656 (May 26, 2011) (''*Preliminary Determination*'').

[2] *See Multilayered Wood Flooring from the People's Republic of China: Amended Preliminary Determination of Sales at Less Than Fair Value,* 76 FR 37316 (June 27, 2011) (''*Amended Preliminary Determination*'').

[3] *See* the ''Verification'' section below.

[4] Letter from Zhejiang Layo Wood Industry Co., Ltd. to Secretary of Commerce, ''Multilayered Wood Flooring From the People's Republic of China: Resubmission of August 5, 2011 Case Brief'' (Aug. 15, 2011).

[5] *See* 19 CFR 351.204(b)(1).

[6] *See* Memorandum from Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, to Ronald K. Lorentzen, Deputy Assistant Secretary for Import Administration, ''Issues and Decision Memorandum for the Final Determination in the Antidumping Duty Investigation of Wood Flooring from the People's Republic of China'' (October 11, 2011) (''Issues and Decision Memorandum'').

[7] *See* Issues and Decision Memorandum at Comment 16; *see also* Memorandum regarding:

2. The Department changed the SV for high density fiberboard inputs from Philippine HTS 4411.19 to a simple average of Philippine HTS 4411.11 and Philippine HTS 4411.21.[8]

3. To value plywood, the Department is relying on the Philippines Department of Environment and Natural Resources, Forest Management Bureau (''FMB'')'s 2009 price data for lauan plywood, inflated to the POI. In doing so, the Department is averaging the prices of 4.7625 millimeter (mm) thick, 6.35 mm thick, and 12.7 mm thick plywood for all of 2009.[9]

4. The Department is valuing the Samling Group's finish inputs (*i.e.,* top coat and base coat) and Layo Wood's paint inputs using POI Philippine National Statistics Office (''NSO'') data from the eight-digit Philippine HTS category 3208.20.90.[10]

5. The Department changed the data it relied upon to calculate a surrogate labor rate from 2006 ''compensation of employees'' data to 2002 ''labor cost'' data.[11]

6. The Department changed the financial statements used to calculate financial ratios from four 2009 statements of Philippine plywood producers to three 2010 statements of Philippine plywood producers.[12]

7. The Department changed the source of information it used to calculate the truck rate from Indian truck rate data to the Confederation of Truckers Association of the Philippines, Inc.[13]

8. The Department stated in its Preliminary Surrogate Value Memorandum that it was relying upon the International Monetary Fund's (''IMF'') Wholesale Price Index (''WPI'') for the Philippines and India to reflect inflation or deflation of non-contemporaneous surrogate values.[14] The Department, instead, inadvertently used the IMF's Consumer Price Index (''CPI'') for the Philippines and India in its surrogate value calculations. Although no parties commented on this issue, the Department has changed the indices it used in inflation and deflation calculations for the final determination, to reflect its originally intended methodology. Due to changes in IMF index reporting terminology, the Department finds that the closest available index for the Philippines and India is the Producer Price Index (''PPI''). Therefore, the Department has calculated the inflation or deflation of non-contemporaneous surrogate values for the final determination based on PPI.[15]

9. In the *Preliminary Determination,* the Department used an electricity rate with an effective date of 2009, and inflated it to the POI. For the final determination, the Department finds that inflating the electricity rate does not represent the best available information because utility rates generally represent the current rate as of the listed effective date. Therefore, the Department did not inflate the electricity value to the POI for the final determination.[16]

10. For the final determination the Department we have valued Layo Wood's byproducts using a simple average of the surrogate values for Layo Wood's wood veneer and wood core inputs.

Changes Specific to Yuhua

We made changes based on verification findings.[17]

Changes Specific to Layo Wood

1. The Department changed the SV for Layo Wood's glue inputs from Philippine HTS 3506.99 to Philippine HTS 3909.20.90.[18]

2. The Department changed the rate used to calculate the density of Layo Wood's packing fiberboard inputs from 740 kg per cubic meter to 650 kg per cubic meter.[19]

Changes Specific to Samling Group

1. The Department is valuing the Samling Group's glue input using POI NSO data from the eight-digit Philippine HTS category 3909.10.90, ''other; urea formaldehyde adhesive.'' [20]

2. The Department is valuing certain Samling veneers using 2009 NSO data for Philippine HTS category 4408.39.90, which covers tropical wood veneers.[21]

3. The Department is valuing the Samling Group's corrugated cardboard inputs using POI NSO data from the six-digit Philippine HTS category 4808.10, ''Corrugated paper and paperboard, whether or not perforated.'' [22]

4. The Department is valuing the Samling Group's label inputs using POI NSO data from the six-digit Philippine HTS category 4811.41, ''Self-adhesive.'' [23]

5. The Department is valuing certain market economy purchases using the corrected values reported by the Samling Group at the verification of Baroque Timber Industries (Zhongshan) Co., Ltd.[24]

6. The Department has reduced the Samling Group's reported gross unit U.S. price by Samling's costs associated with U.S. inland freight from the warehouse to customer (*i.e.,* we reduced the reported gross unit price by the INLFWCU field).[25]

7. The Department is treating freight revenue as an offset to freight costs rather than as an addition to U.S. price.[26]

8. The Department adjusted the Samling Group's indirect selling expense ratio to include the POI total reserve for bad debt expense.[27]

Antidumping Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Final Surrogate Value Memorandum dated concurrently with this memorandum (''Final Surrogate Value Memorandum'').

[8] *See* Issues and Decision Memorandum at Comment 20; *see also* Final Surrogate Value Memorandum.

[9] *See* Issues and Decision Memorandum at Comment 13; *see also* Final Surrogate Value Memorandum.

[10] *See* Issues and Decision Memorandum at Comment 19; *see* Memorandum regarding: Antidumping Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Final Determination Analysis Memorandum for the Samling Group, dated concurrently with this memorandum (''Samling's Final Analysis Memo''); *see* Memorandum regarding: Antidumping Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Final Determination Analysis Memorandum for Layo Wood, dated concurrently with this memorandum (''Layo Wood's Final Analysis Memo'').

[11] *See* Issues and Decision Memorandum at Comment 6; *see also* Final Surrogate Value Memorandum.

[12] *See* Issues and Decision Memorandum at Comment 1; *see also* Final Surrogate Value Memorandum.

[13] *See* Issues and Decision Memorandum at Comment 18; *see also* Final Surrogate Value Memorandum.

[14] *See* Memorandum regarding: Antidumping Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Preliminary Surrogate Value Memorandum, dated May 19, 2011, (''Preliminary Surrogate value Memorandum'') at 2–3.

[15] *See* Final Surrogate Value Memorandum.

[16] *See* Final Surrogate Value Memorandum.

[17] *See* Yuhua's Verification Report; *see* Memorandum Regarding: Antidumping Duty Investigation of Multilayered Wood Flooring from the People's Republic of China: Final Determination Analysis Memorandum for Yuhua, dated concurrently with this memorandum (''Yuhua's Final Analysis Memo'').

[18] *See* Issues and Decision Memorandum at Comment 25; *see* Layo Wood's Final Analysis Memo.

[19] *See* Issues and Decision Memorandum at Comment 30; *see* Layo Wood's Final Analysis Memo.

[20] *See* Issues and Decision Memorandum at Comment 32; *see* Samling's Final Analysis Memo.

[21] *See* Issues and Decision Memorandum at Comment 31; *see* Samling's Final Analysis Memo.

[22] *See* Issues and Decision Memorandum at Comment 35; *see also* Samling's Final Analysis Memo.

[23] *See* Issues and Decision Memorandum at Comment 33; *see also* Samling's Final Analysis Memo.

[24] *See* Samling's Final Analysis Memo.

[25] *See* Issues and Decision Memorandum at Comment 38; *see* Samling's Final Analysis Memo.

[26] *See* Issues and Decision Memorandum at Comment 39; *see* Samling's Final Analysis Memo.

[27] *See* Issues and Decision Memorandum at Comment 40; *see* Samling's Final Analysis Memo.

Scope of the Investigation [28]

Multilayered wood flooring is composed of an assembly of two or more layers or plies of wood veneer(s) [29] in combination with a core. The several layers, along with the core, are glued or otherwise bonded together to form a final assembled product. Multilayered wood flooring is often referred to by other terms, *e.g.,* ''engineered wood flooring'' or ''plywood flooring.'' Regardless of the particular terminology, all products that meet the description set forth herein are intended for inclusion within the definition of subject merchandise.

All multilayered wood flooring is included within the definition of subject merchandise, without regard to: dimension (overall thickness, thickness of face ply, thickness of back ply, thickness of core, and thickness of inner plies; width; and length); wood species used for the face, back and inner veneers; core composition; and face grade. Multilayered wood flooring included within the definition of subject merchandise may be unfinished (*i.e.,* without a finally finished surface to protect the face veneer from wear and tear) or ''prefinished'' (*i.e.,* a coating applied to the face veneer, including, but not exclusively, oil or oil-modified or water-based polyurethanes, ultra-violet light cured polyurethanes, wax, epoxy-ester finishes, moisture-cured urethanes and acid-curing formaldehyde finishes). The veneers may be also soaked in an acrylic-impregnated finish. All multilayered wood flooring is included within the definition of subject merchandise regardless of whether the face (or back) of the product is smooth, wire brushed, distressed by any method or multiple methods, or hand-scraped. In addition, all multilayered wood flooring is included within the definition of subject merchandise regardless of whether or not it is manufactured with any interlocking or connecting mechanism (for example, tongue-and-groove construction or locking joints). All multilayered wood flooring is included within the definition of the subject merchandise regardless of whether the product meets a particular industry or similar standard.

The core of multilayered wood flooring may be composed of a range of materials, including but not limited to hardwood or softwood veneer, particleboard, medium-density fiberboard (''MDF''), high-density fiberboard (''HDF''), stone and/or plastic composite, or strips of lumber placed edge-to-edge.

Multilayered wood flooring products generally, but not exclusively, may be in the form of a strip, plank, or other geometrical patterns (*e.g.,* circular, hexagonal). All multilayered wood flooring products are included within this definition regardless of the actual or nominal dimensions or form of the product.

Specifically excluded from the scope are cork flooring and bamboo flooring, regardless of whether any of the sub-surface layers of either flooring are made from wood. Also excluded is laminate flooring. Laminate flooring consists of a top wear layer sheet not made of wood, a decorative paper layer, a core-layer of high-density fiberboard, and a stabilizing bottom layer.

Imports of the subject merchandise are provided for under the following subheadings of the Harmonized Tariff Schedule of the United States (''HTSUS''): 4412.31.0520; 4412.31.0540; 4412.31.0560; 4412.31.2510; 4412.31.2520; 4412.31.4040; 4412.31.4050; 4412.31.4060; 4412.31.4070; 4412.31.5125; 4412.31.5135; 4412.31.5155; 4412.31.5165; 4412.31.3175; 4412.31.6000; 4412.31.9100; 4412.32.0520; 4412.32.0540; 4412.32.0560; 4412.32.2510; 4412.32.2520; 4412.32.3125; 4412.32.3135; 4412.32.3155; 4412.32.3165; 4412.32.3175; 4412.32.3185; 4412.32.5600; 4412.39.1000; 4412.39.3000; 4412.39.4011; 4412.39.4012; 4412.39.4019; 4412.39.4031; 4412.39.4032; 4412.39.4039; 4412.39.4051; 4412.39.4052; 4412.39.4059; 4412.39.4061; 4412.39.4062; 4412.39.4069; 4412.39.5010; 4412.39.5030; 4412.39.5050; 4412.94.1030; 4412.94.1050; 4412.94.3105; 4412.94.3111; 4412.94.3121; 4412.94.3131; 4412.94.3141; 4412.94.3160; 4412.94.3171; 4412.94.4100; 4412.94.5100; 4412.94.6000; 4412.94.7000; 4412.94.8000; 4412.94.9000; 4412.94.9500; 4412.99.0600; 4412.99.1020; 4412.99.1030; 4412.99.1040; 4412.99.3110; 4412.99.3120; 4412.99.3130; 4412.99.3140; 4412.99.3150; 4412.99.3160; 4412.99.3170; 4412.99.4100; 4412.99.5100; 4412.99.5710; 4412.99.6000; 4412.99.7000; 4412.99.8000; 4412.99.9000; 4412.99.9500; 4418.71.2000; 4418.71.9000; 4418.72.2000; and 4418.72.9500.

In addition, imports of subject merchandise may enter the United States under the following HTSUS subheadings: 4409.10.0500; 4409.10.2000; 4409.29.0515; 4409.29.0525; 4409.29.0535; 4409.29.0545; 4409.29.0555; 4409.29.0565; 4409.29.2530; 4409.29.2550; 4409.29.2560; 4418.71.1000; 4418.79.0000; and 4418.90.4605.

While HTSUS subheadings are provided for convenience and customs purposes, the written description of the subject merchandise is dispositive.

Scope Comments

Scope Comments

Following the *Preliminary Determination,* on May 19, 2011, the Department issued a decision memorandum addressing multiple scope issues in this and the concurrent CVD investigation of wood flooring from the PRC. *See* Memorandum to Christian Marsh, ''Scope'' (May 19, 2011) (''Scope Memo''). We sought comments on the scope in both the AD and CVD cases. *See* Letter to All Interested Parties from Nancy Decker, Program Manager, Office 1, AD/CVD Operations, Import Administration, ''RE: Antidumping and Countervailing Duty Investigations: *Multilayered Wood Flooring from the People's Republic of China,''* (May 25, 2011).

In response, interested parties filed scope-related comments in submissions on June 6, 2011, June 14, 2011, and June 15, 2011, as well as in case briefs on August 4, 2011, and rebuttal briefs on August 8, 2011, and August 9, 2011. Additionally, a scope-related submission was received the same day the Scope Memo was released and, therefore, was not analyzed in the Scope Memo, but is addressed in this final determination. Based on our analysis of all the comments, we have changed the scope to eliminate references to certain HTSUS numbers. For a complete discussion of this change, as well as a summary of the parties' comments and the Department's positions, *see* the Issues and Decision Memorandum.

Verification

As provided in section 782(i) of the Act, the Department verified the information submitted by Yuhua, Layo Wood, and the Samling Group for use in its final determination. The Department used standard verification procedures, including examination of relevant accounting and production records and

[28] *See* Memorandum to Christian Marsh through Susan Kuhbach and Nancy Decker from Joshua Morris ''Multilayered Wood Flooring from the People's Republic of China; Scope,'' dated May 19, 2011.

[29] A ''veneer'' is a thin slice of wood, rotary cut, sliced or sawed from a log, bolt or flitch. Veneer is referred to as a ply when assembled.

original source documents provided by the respondents.[30]

Non-Market Economy Country

The Department considers the PRC to be a non-market economy (''NME'') country. In accordance with section 771(18)(C)(i) of the Act, any determination that a foreign country is an NME country shall remain in effect until revoked by the administering authority. The Department has not revoked the PRC's status as an NME country. No party has challenged the designation of the PRC as an NME country in this investigation. Therefore, the Department continues to treat the PRC as an NME for purposes of this final determination.

Surrogate Country

In the preliminary determination, the Department stated that it selected the Philippines as the appropriate surrogate country to use in this investigation pursuant to section 773(c)(4) of the Act based on the following: (1) It is at a similar level of economic development; (2) it is a significant producer of comparable merchandise; and (3) we have reliable data from the Philippines that we can use to value the FOPs.[31] The Department has not made changes to findings with respect to the selection of a surrogate country for the final determination.

Separate Rate Companies

In proceedings involving NME countries, the Department holds a rebuttable presumption that all companies within the country are subject to government control and, thus, should be assessed a single antidumping duty rate. It is the Department's policy to assign all exporters of the subject merchandise in an NME country this single rate unless an exporter can demonstrate that it is sufficiently independent so as to be entitled to a separate rate.[32]

In the instant investigation, the Department received timely-filed separate rate applications (''SRAs'') from 74 companies (''Separate Rate Applicants'').[33] In the *Preliminary Determination,* the Department found that twelve wholly foreign-owned companies,[34] demonstrated eligibility for separate rate status.[35] In addition, the Department found that sixty-two of the separate-rate companies that are either joint ventures between Chinese and foreign companies or are wholly Chinese-owned companies demonstrated eligibility for separate rate status. Since the publication of the *Preliminary Determination,* no party has commented on the eligibility of the Separate Rate Applicants for separate-rate status. However, the Department corrected the name of one of the separate rate applicants. The Department has changed the incorrect name of ''Shanghai Lizhong Wood Products Co., Ltd. (''Lizhong'')'' to the correct name of ''Shanghai Lizhong Wood Products Co., Ltd. also known as The Lizhong Wood Industry Limited Company of Shanghai (''Lizhong'').'' [36]

[30] *See* Memorandum from Brandon Petelin, International Trade Analyst, AD/CVD Operations, Office 4, to the File, Verification of Constructed Export Sales (''CEP'') for Baroque Timber Industries (Zhongshan) Co., Ltd. (''BTI''), Riverside Plywood Corporation (''RPC''), Samling Elegant Living Trading (Labuan) Limited (''SELT''), Samling Riverside Co., Ltd.(''SR''), and Suzhou Times Flooring Co., Ltd. (''STF'') (collectively, the ''Samling Group'') at the headquarters of its U.S. affiliate (July 22, 2011); Memorandum from Robert Greger, Senior International Trade Accountant, AD/CVD Operations, Office 4, to the File, Verification of Constructed Export Sales (''CEP'') for Baroque Timber Industries (Zhongshan) Co., Ltd. (''BTI''), Riverside Plywood corporation (''RPC''), Samling Elegant Living Trading (Labuan) Limited (''SELT''), Samling Riverside Co., Ltd. (''SR''), and Suzhou Times Flooring Co., Ltd. (''STF'') (collectively, the ''Samling Group'') at Samling Global USA, Inc. (''SGUSA'') (July 22, 2011); Memorandum from Brandon Farlander, Senior International Trade Analyst, AD/CVD Operations, Office 4, to the File, Verification of the Questionnaire Responses of Zhejiang Yuhua Timber Co., Ltd (''Yuhua'') (July 21, 2011) (''Yuhua's Verification Report''); Memorandum from Brandon Farlander, Senior International Trade Analyst, AD/CVD Operations, Office 4, to the File, Verification of the Sales and Factors Response of Zhejiang Layo Wood Industry Co., Ltd., in Less than Fair Value Investigation of Multilayered Wood Flooring from the People's Republic of China (July 22, 2011); Memorandum from Brandon Petelin, International Trade Analyst, AD/CVD Operations, Office 4, to the File, Verification of Sales and Factors Response of Baroque Timber Industries (Zhongshan) Co., Ltd. (''BTI'') and Samling Elegant Living Trading (Labuan) Limited (''SELT'') in the Less-than-Fair-Value Investigation of Multilayered Wood Flooring (''Wood Flooring'') from the People's Republic of China (''PRC'') (July 22, 2011); Memorandum from Brandon Petelin, International Trade Analyst, AD/CVD Operations, Office 4, to the File, Verification of Sales and Factors Response of Riverside Plywood Corporation (''RPC'') and Samling Riverside Co., Ltd. (''SR'') in the Less-than-Fair-Value Investigation of Multilayered Wood Flooring (''Wood Flooring'') from the People's Republic of China (''PRC'') (July 22, 2011).

[31] *See* Memorandum to Abdelali Elouaradia from Drew Jackson, Multilayered Wood Flooring from the People's Republic of China: Surrogate Country Memorandum (May 19, 2011).

[32] *See Notice of Final Determination of Sales at Less Than Fair Value: Sparklers from the People's Republic of China,* 56 FR 20588 (May 6, 1991), and accompanying Issues and Decision Memorandum at Cmt. 1; as further developed in *Notice of Final Determination of Sales at less Than Fair Value Silicon Carbide from the People's Republic of China,* 59 FR 22585, 22587 (May 2, 1994).

[33] The 74 separate-rate applicants are: (1) MuDanJiang Bosen Wood Industry Co., Ltd., (2) Huzhou Chenghang Wood Co., Ltd., (3) Hangzhou Hanje Tec Co., Ltd., (4) Nakahiro Jyou Sei Furniture (Dalian) Co., Ltd., (5) Shenyang Haobainian Wooden Co., Ltd., (6) Dalian Dajen Wood Co., Ltd., (7) HaiLin LinJing Wooden Products, Ltd., (8) Dun Hua Sen Tai Wood Co., Ltd., (9) Dunhua Jisheng Wood Industry Co., Ltd., (10) Hunchun Forest Wolf Industry Co., Ltd., (11) Guangzhou Panyu Southern Star Co., Ltd., (12) Nanjing Minglin Wooden Industry Co., Ltd., (13) Zhejiang Fudeli Timber Industry Co., Ltd., (14) Suzhou Dongda Wood Co., Ltd., (15) Guangzhou Pan Yu Kang Da Board Co., Ltd., (16) Kornbest Enterprises Ltd., (17) Metropolitan Hardwood Floors, Inc., (18) Zhejiang Longsen Lumbering Co., Ltd., (19) Xinyuan Wooden Industry Co., Ltd., (20) Dasso Industrial Group Co., Ltd., (21) Hong Kong Easoon Wood Technology Co., Ltd., (22) Armstrong Wood Products (Kunshan) Co., Ltd., (23) Baishan Huafeng Wooden Product Co., Ltd., (24) Changbai Mountain Development and Protection Zone Hongtu Wood Industry Co., Ltd., (25) Changzhou Hawd Flooring Co., Ltd., (26) Dalian Jiuyuan Wood Industry Co., Ltd., (27) Dalian Penghong Floor Products Co., Ltd., (28) Dongtai Fuan Universal Dynamics LLC, (29) Dunhua City Dexin Wood Industry Co., Ltd., (30) Dunhua City Hongyuan Wood Industry Co., Ltd., (31) Dunhua City Jisen Wood Industry Co., Ltd., (32) Dunhua City Wanrong Wood Industry Co., Ltd., (33) Fusong Jinlong Wooden Group Co., Ltd., (34) Fusong Qianqiu Wooden Product Co., Ltd., (35) GTP International, (36) Guangdong Yihua Timber Industry Co., Ltd., (37) HaiLin LinJing Wooden Products, Ltd., (38) Huzhou Fulinmen Imp & Exp. Co., Ltd., (39) Huzhou Fuma Wood Bus. Co., Ltd., (40) Jiafeng Wood (Suzhou) Co., Ltd., (41) Jiashan Hui Jia Le Decoration Material Co., Ltd., (42) Jilin Forest Industry Jinqiao Flooring Group Co., Ltd., (43) Karly Wood Product Limited, (44) Kunshan Yingyi-Nature Wood Industry Co., Ltd., (45) Puli Trading Limited, (46) Shanghai Eswell Timber Co. Ltd., (47) Shanghai Lairunde Wood Co., Ltd., (48) Shanghai New Sihe Wood Co., Ltd., (49) Shanghai Shenlin Corporation, (50) Shenzhenshi Huanwei Woods Co., Ltd., (51) Vicwood Industry (Suzhou) Co., Ltd., (52) Xiamen Yung De Ornament Co., Ltd., (53) Xuzhou Shenghe Wood Co., Ltd., (54) Yixing Lion-King Timber Industry Co., Ltd., (55) Jiangsu Simba Flooring Industry Co., Ltd, (56) Zhejiang Biyork Wood Co., Ltd., (57) Zhejiang Dadongwu GreenHome Wood Co., Ltd., (58) Zhejiang Desheng Wood Industry Co., Ltd., (59) Zhejiang Shiyou Timber Co., Ltd., (60) Zhejiang Tianzhen Bamboo & Wood Development Co., Ltd., (61) Chinafloors Timber (China) Co. Ltd., (62) Shanghai Lizhong Wood Products Co., Ltd., (63) Fine Furniture (Shanghai) Limited, (64) Huzhou Sunergy World Trade Co. Ltd., (65) Huzhou Jesonwood Co., Ltd., (66) A&W (Shanghai) Woods Co., Ltd., (67) Fu Lik Timber (HK) Company Limited, (68) Yekalon Industry, Inc./Sennorwell International Group (Hong Kong) Limited, (69) Kemian Wood Industry (Kunshan) Co., Ltd., (70) Dalian Kemian Wood Industry Co., Ltd., (71) Dalian Huilong Wooden Products Co., Ltd., (72) Jiangsu Senmao Bamboo and Wood Industry Co., Ltd., and (73) Real Wood Floors, LLC.

[34] The wholly foreign-owned Separate Rate Applicants are: (1) Jianfeng Wood (Suzhou) Co, Ltd; (2) Fu Lik Timber (HK) Company Limited; (3) Xiamen Yung De Ornament Co., Ltd; (4) Metropolitan Hardwood Floors, Inc.; (5) A&W (Shanghai) Woods Co., Ltd.; (6) Vicwood Industry (Suzhou) Co., Ltd.; (7) Armstrong Wood Products (Kunshan) Co., Ltd.; (8) Kunshan Yingyi-Nature Wood Industry Co., Ltd.; (9) Dongtai Fuan Universal Dynamics LLC; (10) Yixing Lion-King Timber Industry Co., Ltd.; (11) Chinafloors Timber (China) Co., Ltd.; and (12) Fine Furniture (Shanghai) Limited.

[35] *See Preliminary Determination,* 76 FR at 30661.

[36] *See* Memorandum to Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, from Trisha Tran, International Trade Analyst, Office 4, Multilayered Wood Flooring from the People's Republic of China: Request to Modify Customs Instructions. (July 28, 2011).

For the final determination, the Department continues to find that the evidence placed on the record of this investigation by the Separate Rate Applicants demonstrates both *de jure* and *de facto* absence of government control with respect to each company's respective exports of the merchandise under investigation. Thus, the Department continues to find that the Separate Rate Applicants are eligible for separate-rate status.

The separate rate is normally determined based on the weighted-average of the estimated dumping margins established for exporters and producers individually investigated, excluding zero and *de minimis* margins or margins based entirely on adverse facts available (''AFA'').[37] In this investigation, two of the individually investigated companies, Layo Wood, and the Samling Group, have estimated weighted-average dumping margins which are above *de minimis* and which are not based on total AFA. Therefore, because there are only two relevant weighted-average dumping margins for this final determination, using a weighted-average risks disclosure of business proprietary information. Accordingly, the Department has calculated the separate rate using a simple-average of these two margins, which is 3.31 percent.[38]

Use of Facts Available and Adverse Facts Available

Section 776(a) of the Act provides that the Department shall apply facts available (''FA'') if (1) necessary information is not on the record, or (2) an interested party or any other person (A) withholds information that has been requested, (B) fails to provide information within the deadlines established, or in the form and manner requested by the Department, subject to subsections (c)(1) and (e) of section 782 of the Act, (C) significantly impedes a proceeding, or (D) provides information that cannot be verified as provided by section 782(i) of the Act.

Section 776(b) of the Act further provides that the Department may use an adverse inference in applying FA when a party has failed to cooperate by not acting to the best of its ability to comply with a request for information. Such an adverse inference may include reliance on information derived from the petition, the final determination, a previous administrative review, or other information placed on the record.

PRC-Wide Entity

In the *Preliminary Determination,* the Department determined that certain PRC exporters/producers did not respond to the Department's requests for information including information pertaining to whether they were separate from the PRC-wide entity.[39] Thus, the Department has found that these PRC exporters/producers are part of the PRC-wide entity and the PRC-wide entity has not responded to our requests for information.[40] No additional information was placed on the record with respect to any of these companies after the preliminary determination. Because the PRC-wide entity did not provide the Department with requested information, pursuant to section 776(a)(2)(A) of the Act, the Department continues to find it appropriate to base the PRC-wide rate on FA.

The Department determines that, because the PRC-wide entity did not respond to our request for information, the PRC-wide entity has failed to cooperate to the best of its ability. Therefore, pursuant to section 776(b) of the Act, the Department finds that, in selecting from among the FA, an adverse inference is appropriate for the PRC-wide entity.

Because the Department begins with the presumption that all companies within an NME country are subject to government control, and because only the mandatory respondents and the Separate Rate Applicants have overcome that presumption, the Department is applying a single antidumping rate to all other exporters of subject merchandise from the PRC. Such companies have not demonstrated entitlement to a separate rate.[41] Accordingly, the PRC-wide entity rate applies to all entries of subject merchandise except for entries from Yuhua, Layo Wood, the Samling Group, and the Separate Rate Applicants.

Selection of the AFA Rate for the PRC-Wide Entity

In selecting a rate for AFA, the Department selects a rate that is sufficiently adverse ''as to effectuate the purpose of the adverse facts available rule to induce respondents to provide the Department with complete and accurate information in a timely manner.''[42] Further, it is the Department's practice to select a rate that insures ''that the party does not obtain a more favorable result by failing to cooperate than if it had cooperated fully.''[43] It is the Department's practice to select as AFA the higher of the (a) highest margin alleged in the petition or (b) the highest calculated rate of any respondent in the investigation.[44] In order to determine the probative value of the margins in the petition for use as AFA for purposes of this final determination, we analyzed the U.S. prices and normal values for each of the individually investigated parties. Based on this analysis, we determined that while there were U.S. prices within the range of the prices contained in the petition, the normal value information contained in the petition does not have probative value for purposes of this final determination. The Department does not find the highest calculated rate of the mandatory respondents to be sufficiently adverse to act as the AFA rate. With respect to AFA, for the final determination, we have assigned the PRC-wide entity the rate of 58.84 percent, the highest calculated transaction-specific rate among mandatory respondents. No corroboration of this rate is necessary because we are relying on information obtained in the course of this investigation, rather than secondary information.[45]

The dumping margin for the PRC-wide entity applies to all entries of the merchandise under investigation except for entries of merchandise under investigation from the exporter/manufacturer combinations listed in the chart in the ''Final Determination'' section below.

Combination Rates

In the *Initiation Notice,* the Department stated that it would calculate combination rates for respondents that are eligible for a

[37] *See* section 735(c)(5)(A) of the Act.

[38] *See Certain Cased Pencils From the People's Republic of China: Final Results of the Antidumping Duty Administrative Review,* 75 FR 38980 (July 2010) at Comment 4.

[39] *See Preliminary Determination,* 76 FR at 30661.

[40] *Id.*

[41] *See, e.g., Notice of Final Determination of Sales at Less Than Fair Market Value: Synthetic Indigo From the People's Republic of China,* 65 FR 25706, 25707 (May 2, 2000).

[42] *See Notice of Final Determination of Sales at Less than Fair Value: Static Random Access Memory Semiconductors From Taiwan,* 63 FR 8909, 8932 (Feb. 23, 1998).

[43] *See Brake Rotors from the People's Republic of China: Final Results and Partial Rescission of the Seventh Administrative Review; Final Results of the Eleventh New Shipper Review,* 70 FR 69937, 69939 (Nov. 18, 2005)(quoting the Statement of Administrative Action accompanying the Uruguay Round Agreements Act, H. Doc. No. 316, 103d Cong., 2d Session at 870 (1994)).

[44] *See, e.g., Seamless Refined Copper Pipe and Tube From the People's Republic of China: Final Determination of Sales at Less Than Fair Value,* 75 FR 60725, 60729 (October 1, 2010).

[45] *See* 19 CFR 351.308(c) and (d) and section 776(c) of the Act; *see also Final Determination of Sales at Less Than Fair Value and Affirmative Determination of Critical Circumstances, in Part: Light-Walled Rectangular Pipe and Tube from the People's Republic of China,* 73 FR 35652, 35653 (June 24, 2008), and accompanying Issues and Decision Memorandum at 1.

separate rate in this investigation.[46] This practice is described in Policy Bulletin 05.1, available at *http://www.trade.gov/ia.* In the *Amended Preliminary Determination,* the Department stated that it did not grant separate combination rates to Tak Wah Building Material (Suzhou) Co. Ltd. (''Tak Wah'') and Tech Wood International Ltd. (''Tech Wood''), the affiliated exporters on whose behalf Vicwood submitted a separate rate application, due to incomplete and conflicting information in Vicwood's previous responses.[47] On July 6, 2011, the Department received supplemental questionnaire responses from Vicwood supplying the clarifying information requested by the Department. As a result, the department is granting separate combination rates to exporters Tak Wah and Tech Wood for merchandise produced by Vicwood.

Final Determination

The Department determines that the following dumping margins exist for the period April 1, 2010, through September 30, 2010:

Exporter	Producer	Weighted average margin
Zhejiang Layo Wood Industry Co., Ltd	Zhejiang Layo Wood Industry Co., Ltd	3.98
The Samling Group**	The Samling Group**	2.63
Zhejiang Yuhua Timber Co., Ltd	Zhejiang Yuhua Timber Co., Ltd	0.00
Jiaxing Brilliant Import & Export Co., Ltd	Zhejiang Layo Wood Industry Co., Ltd	3.31
MuDanJiang Bosen Wood Industry Co., Ltd	MuDanJiang Bosen Wood Industry Co., Ltd	3.31
MuDanJiang Bosen Wood Industry Co., Ltd	Dun Hua Sen Tai Wood Co., Ltd	3.31
Huzhou Chenghang Wood Co., Ltd	Huzhou Chenghang Wood Co., Ltd	3.31
Hangzhou Hanje Tec Co., Ltd	Zhejiang Jiechen Wood Industry Co., Ltd	3.31
Nakahiro Jyou Sei Furniture (Dalian) Co., Ltd	Nakahiro Jyou Sei Furniture (Dalian) Co., Ltd	3.31
Shenyang Haobainian Wooden Co., Ltd	Shenyang Sende Wood Co., Ltd	3.31
Shenyang Haobainian Wooden Co., Ltd	Shenyang Haobainian Wooden Co., Ltd	3.31
Shenyang Haobainian Wooden Co., Ltd	Shanghai Demeijia Wooden Co., Ltd	3.31
Dalian Dajen Wood Co., Ltd	Dalian Dajen Wood Co., Ltd	3.31
HaiLin LinJing Wooden Products, Ltd	HaiLin LinJing Wooden Products, Ltd	3.31
Dun Hua Sen Tai Wood Co., Ltd	Dun Hua Sen Tai Wood Co., Ltd	3.31
Dunhua Jisheng Wood Industry Co., Ltd	Dunhua Jisheng Wood Industry Co., Ltd	3.31
Hunchun Forest Wolf Industry Co., Ltd	Hunchun Forest Wolf Industry Co., Ltd	3.31
Guangzhou Panyu Southern Star Co., Ltd	Guangzhou Jiasheng Timber Industry Co., Ltd	3.31
Nanjing Minglin Wooden Industry Co., Ltd	Nanjing Minglin Wooden Industry Co., Ltd	3.31
Zhejiang Fudeli Timber Industry Co., Ltd	Zhejiang Fudeli Timber Industry Co., Ltd	3.31
Suzhou Dongda Wood Co., Ltd	Suzhou Dongda Wood Co., Ltd	3.31
Guangzhou Pan Yu Kang Da Board Co., Ltd	Guangzhou Pan Yu Kang Da Board Co., Ltd	3.31
Kornbest Enterprises Ltd	Guangzhou Pan Yu Kang Da Board Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Dalian Huilong Wooden Products Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Mudanjiang Bosen Wood Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Nakahiro Jyou Sei Furniture (Dalian) Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Hunchun Forest Wolf Wooden Industry Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Kemian Wood Industry (Kunshan) Co., Ltd	3.31
Metropolitan Hardwood Floors, Inc	Shenyang Haobainian Wooden Co., Ltd	3.31
Zhejiang Longsen Lumbering Co., Ltd	Zhejiang Longsen Lumbering Co., Ltd	3.31
Xinyuan Wooden Industry Co., Ltd	Xinyuan Wooden Industry Co., Ltd	3.31
Dasso Industrial Group Co., Ltd	Dasso Industrial Group Co., Ltd	3.31
Hong Kong Easoon Wood Technology Co., Ltd	Dasso Industrial Group Co., Ltd	3.31
Armstrong Wood Products (Kunshan) Co., Ltd	Armstrong Wood Products (Kunshan) Co., Ltd	3.31
Baishan Huafeng Wooden Product Co., Ltd	Baishan Huafeng Wooden Product Co., Ltd	3.31
Changbai Mountain Development and Protection Zone Hongtu Wood Industry Co., Ltd.	Changbai Mountain Development and Protection Zone Hongtu Wood Industry Co., Ltd.	3.31
Changzhou Hawd Flooring Co., Ltd	Changzhou Hawd Flooring Co., Ltd	3.31
Dalian Jiuyuan Wood Industry Co., Ltd	Dalian Jiuyuan Wood Industry Co., Ltd	3.31
Dalian Penghong Floor Products Co., Ltd	Dalian Penghong Floor Products Co., Ltd	3.31
Dongtai Fuan Universal Dynamics LLC	Dongtai Fuan Universal Dynamics LLC	3.31
Dunhua City Dexin Wood Industry Co., Ltd	Dunhua City Dexin Wood Industry Co., Ltd	3.31
Dunhua City Hongyuan Wood Industry Co., Ltd	Dunhua City Hongyuan Wood Industry Co., Ltd	3.31
Dunhua City Jisen Wood Industry Co., Ltd	Dunhua City Jisen Wood Industry Co., Ltd	3.31
Dunhua City Wanrong Wood Industry Co., Ltd	Dunhua City Wanrong Wood Industry Co., Ltd	3.31
Fusong Jinlong Wooden Group Co., Ltd	Fusong Jinlong Wooden Group Co., Ltd	3.31
Fusong Qianqiu Wooden Product Co., Ltd	Fusong Qianqiu Wooden Product Co., Ltd	3.31
GTP International	Jiangsu Senmao Bamboo and Wood Industry Co., Ltd	3.31
GTP International	Jiafeng Wood (Suzhou) Co., Ltd	3.31
GTP International	Suzhou Dongda Wood Co., Ltd	3.31
GTP International	Kemian Wood Industry (Kunshan) Co., Ltd	3.31
Guangdong Yihua Timber Industry Co., Ltd	Guangdong Yihua Timber Industry Co., Ltd	3.31
HaiLin LinJing Wooden Products, Ltd	HaiLin LinJing Wooden Products, Ltd	3.31
Huzhou Fulinmen Imp & Exp. Co., Ltd	Huzhou Fulinmen Wood Floor Co., Ltd	3.31
Huzhou Fuma Wood Bus. Co., Ltd	Huzhou Fuma Wood Bus. Co., Ltd	3.31
Jiafeng Wood (Suzhou) Co., Ltd	Jiafeng Wood (Suzhou) Co., Ltd	3.31

[46] *See Initiation Notice,* 75 FR at 22113–14.

[47] *See* Memorandum to Abdelali Elouaradia, Director, AD/CVD Operations, Office 4, through Charles Riggle, from Brandon Petelin and Erin Kearney, Preliminary Determination of Antidumping Duty Investigation on Multilayered Wood Flooring from the People's Republic of China: Allegations of Ministerial Errors, dated June 20, 2011, at 4–5.

Exporter	Producer	Weighted average margin
Jiashan Hui Jia Le Decoration Material Co., Ltd	Jiashan Hui Jia Le Decoration Material Co., Ltd	3.31
Jilin Forest Industry Jinqiao Flooring Group Co., Ltd	Jilin Forest Industry Jinqiao Flooring Group Co., Ltd	3.31
Karly Wood Product Limited	Karly Wood Product Limited	3.31
Kunshan Yingyi-Nature Wood Industry Co., Ltd	Kunshan Yingyi-Nature Wood Industry Co., Ltd	3.31
Puli Trading Ltd	Baiying Furniture Manufacturer Co., Ltd	3.31
Shanghai Eswell Timber Co. Ltd	Shanghai Eswell Timber Co. Ltd	3.31
Shanghai Lairunde Wood Co., Ltd	Shanghai Lairunde Wood Co., Ltd	3.31
Shanghai New Sihe Wood Co., Ltd	Shanghai New Sihe Wood Co., Ltd	3.31
Shanghai Shenlin Corporation	Shanghai Shenlin Corporation	3.31
Shenzhenshi Huanwei Woods Co., Ltd	Shenzhenshi Huanwei Woods Co., Ltd	3.31
Tak Wah Building Material (Suzhou) Co. Ltd	Vicwood Industry (Suzhou) Co., Ltd	3.31
Tech Wood International Ltd	Vicwood Industry (Suzhou) Co., Ltd	3.31
Xiamen Yung De Ornament Co., Ltd	Xiamen Yung De Ornament Co., Ltd	3.31
Xuzhou Shenghe Wood Co., Ltd	Xuzhou Shenghe Wood Co., Ltd	3.31
Yixing Lion-King Timber Industry Co., Ltd	Yixing Lion-King Timber Industry Co., Ltd	3.31
Jiangsu Simba Flooring Industry Co., Ltd	Yixing Lion-King Timber Industry Co., Ltd	3.31
Zhejiang Biyork Wood Co., Ltd	Zhejiang Biyork Wood Co., Ltd	3.31
Zhejiang Dadongwu GreenHome Wood Co., Ltd	Zhejiang Dadongwu GreenHome Wood Co., Ltd	3.31
Zhejiang Desheng Wood Industry Co., Ltd	Zhejiang Desheng Wood Industry Co., Ltd	3.31
Zhejiang Shiyou Timber Co., Ltd	Zhejiang Shiyou Timber Co., Ltd	3.31
Zhejiang Tianzhen Bamboo & Wood Development Co., Ltd	Zhejiang Tianzhen Bamboo & Wood Development Co., Ltd	3.31
Chinafloors Timber (China) Co. Ltd	Chinafloors Timber (China) Co. Ltd	3.31
Shanghai Lizhong Wood Products Co., Ltd., also known as The Lizhong Wood Industry Limited Company of Shanghai.	Shanghai Lizhong Wood Products Co., Ltd., also known as The Lizhong Wood Industry Limited Company of Shanghai.	3.31
Fine Furniture (Shanghai) Limited	Fine Furniture (Shanghai) Limited	3.31
Huzhou Sunergy World Trade Co. Ltd	Zhejiang Haoyun Wood Co., Ltd	3.31
Huzhou Sunergy World Trade Co. Ltd	Nanjing Minglin Wooden Industry Co., Ltd	3.31
Huzhou Sunergy World Trade Co. Ltd	Zhejiang AnJi XinFeng Bamboo & Wood Co., Ltd	3.31
Huzhou Jesonwood Co., Ltd	Zhejiang Jeson Wood Co., Ltd	3.31
Huzhou Jesonwood Co., Ltd	Huzhou Jesonwood Co., Ltd	3.31
A&W (Shanghai) Woods Co., Ltd	A&W (Shanghai) Woods Co., Ltd	3.31
A&W (Shanghai) Woods Co., Ltd	Suzhou Anxin Weiguang Timber Co., Ltd	3.31
Fu Lik Timber (HK) Company Limited	Guangdong Fu Lin Timber Technology Limited	3.31
Yekalon Industry, Inc./Sennorwell International Group (Hong Kong) Limited.	Jilin Xinyuan Wooden Industry Co., Ltd	3.31
Kemian Wood Industry (Kunshan) Co., Ltd	Kemian Wood Industry (Kunshan) Co., Ltd	3.31
Dalian Kemian Wood Industry Co., Ltd	Dalian Kemian Wood Industry Co., Ltd	3.31
Dalian Huilong Wooden Products Co., Ltd	Dalian Huilong Wooden Products Co., Ltd	3.31
Jiangsu Senmao Bamboo and Wood Industry Co., Ltd	Jiangsu Senmao Bamboo and Wood Industry Co., Ltd	3.31
PRC-wide Entity		58.84

* *de minimis.*

** The Samling Group consists of the following companies: Baroque Timber Industries (Zhongshan) Co., Ltd., Riverside Plywood Corporation, Samling Elegant Living Trading (Labuan) Limited, Samling Riverside Co., Ltd., and Suzhou Times Flooring Co., Ltd.

Disclosure

We intend to disclose the calculations performed to parties in this proceeding within five days of the date of publication of this notice in accordance with 19 CFR 351.224(b).

Continuation of Suspension of Liquidation

In accordance with section 735(c)(1)(B) of the Act, the Department will instruct CBP to continue to suspend liquidation of all appropriate entries of multilayered wood flooring from the PRC as described in the ''Scope of Investigation'' section, entered, or withdrawn from warehouse, for consumption on or after May 26, 2011, the date of publication of the *Preliminary Determination* in the **Federal Register**. The Department will instruct CBP to require a cash deposit or the posting of a bond equal to the weighted-average amount by which the normal value exceeds U.S. price, as indicated above.

International Trade Commission Notification

In accordance with section 735(d) of the Act, we have notified the International Trade Commission (''ITC'') of the final affirmative determination of sales at LTFV. As the Department's final determination is affirmative, in accordance with section 735(b)(2) of the Act, the ITC will determine, within 45 days, whether the domestic industry in the United States is materially injured, or threatened with material injury, by reason of imports of multilayered wood flooring, or sales (or the likelihood of sales) for importation, of the subject merchandise. If the ITC determines that such injury does exist, the Department will issue an antidumping duty order directing CBP to assess, upon further instruction by the Department, antidumping duties on all imports of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the effective date of the suspension of liquidation.

Notification Regarding APO

This notice also serves as a reminder to the parties subject to administrative protective order (''APO'') of their responsibility concerning the disposition of propriety information disclosed under APO in accordance with 19 CFR 351.305. Timely notification of return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a sanctionable violation.

This determination is issued and published in accordance with sections 735(d) and 777(i)(1) of the Act.

Dated: October 11, 2011.

Ronald K. Lorentzen,

Deputy Assistant Secretary for Import Administration.

Appendix I

Issues for Final Determination

General Issues

Comment 1: Financial Ratios
Comment 2: Adjustments to the Petitioner's Surrogate Ratio Calculations
Comment 3: Department's Rejection of Surrogate Value Submissions
Comment 4: Targeted Dumping
Comment 5: Double Remedy
Comment 6: Labor Cost
Comment 7: Whether To Add Domestic Brokerage and Handling Expenses to Material Inputs That Were Valued Using a Market Economy Purchase Price
Comment 8: Brokerage & Handling Adjustments To Account for Letter of Credit Costs
Comment 9: Certain Information Submitted by Petitioner in Surrogate Value Submission
Comment 10: Appropriateness of Countries Within a ''GNI band'' as Surrogate Value Sources
Comment 11: Separate-Rate Margin
Comment 12: Scope Related Issues
Comment 12.A: Exclusion Requests for Plywood Panels or Veneer
Comment 12.B: Strand-Woven Lignocellulosic Flooring
Comment 12.C: Scope Language Regarding HTSUS Subheadings
Comment 12.D: Continued Requests for Certain Exclusions

General Surrogate Value Issues

Comment 13: Surrogate Value for Plywood
Comment 14: Surrogate Value for Tropical Face Veneer
Comment 15: Surrogate Value for Non-Coniferous, Non-Tropical (''NCNT'') Face Veneer
Comment 16: Surrogate Value for NCNT Core Veneer
Comment 17: Surrogate Value for NCNT Logs and Tropical Logs
Comment 18: Domestic Truck Rate
Comment 19: Surrogate Value for Paint Inputs—the Samling Group and Layo Wood
Comment 20: Surrogate Value for HDF

Mandatory Respondent Specific Issues

Yuhua

Comment 21: Yuhua Affiliation

Layo Wood

Comment 22: Layo Wood-Jiaxing Brilliant Affiliation
Comment 23: Whether the Wood Scrap Offset for Layo Wood Should Be Denied
Comment 24: Surrogate Value for Layo Wood's Byproducts
Comment 25: Surrogate Value for Layo Wood's Glue
Comment 26: Surrogate Value for Pigment
Comment 27: Surrogate Value for Printing Ink
Comment 28: Surrogate Value for Paper Manual
Comment 29: Surrogate Value for Tape
Comment 30: Density Conversion for Layo Wood's Packing Fiberboard

The Samling Group

Comment 31: Value of Certain of the Samling Group's Veneer Inputs
Comment 32: Surrogate Value for the Samling Group's Glue Input
Comment 33: Surrogate Value for Labels
Comment 34: Surrogate Value for Cellophane Tape
Comment 35: Surrogate Value for Corrugated Cardboard Carton
Comment 36: Post-Verification Adjustments to the Samling Group's Reported U.S. Sales Data
Comment 36.A: Adjustment to Gross Unit Price
Comment 36.B: U.S. Duties
Comment 37: SGUSA's Transportation Expenses
Comment 38: Inland Freight—Warehouse to Customer
Comment 39: Other Revenue for U.S. Inland Freight
Comment 40: Indirect Selling Expense Ratio of Affiliated Reseller
Comment 41: SGUSA's Indirect Selling Expense Ratio

Other Issues

Comment 42: Correction of Lizhong's Name
Comment 43: Whether the Department Should Have Selected Fine Furniture as a Voluntary Respondent

[FR Doc. 2011–26932 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Institute of Standards and Technology

Advisory Committee on Earthquake Hazards Reduction Meeting

AGENCY: National Institute of Standards and Technology, Department of Commerce.

ACTION: Notice of open meeting.

SUMMARY: The Advisory Committee on Earthquake Hazards Reduction (ACEHR or Committee), will meet on Tuesday, November 8, 2011 from 8:30 a.m. to 5 p.m. and Wednesday, November 9, 2011, from 8:30 a.m. to 4 p.m. The primary purposes of this meeting are to discuss the relationship of Presidential Policy Directive/PPD–8: National Preparedness to National Earthquake Hazards Reduction Program (NEHRP) activities, to review the conclusions of the National Research Council Report on National Earthquake Resilience, and to review NEHRP agency updates on their latest activities. The agenda may change to accommodate Committee business. The final agenda will be posted on the NEHRP Web site at *http://nehrp.gov/.*

DATES: The ACEHR will meet on Tuesday, November 8, 2011, from 8:30 a.m. until 5 p.m. The meeting will continue on Wednesday, November 9, 2011, from 8:30 a.m. until 4 p.m. The meeting will be open to the public.

ADDRESSES: The meeting will be held at the U.S. Department of Commerce, Main Commerce Building, Room 4830, 1401 Constitution Ave., NW., Washington, DC 20230. Please note admittance instructions under the **SUPPLEMENTARY INFORMATION** section of this notice.

FOR FURTHER INFORMATION CONTACT: Dr. Jack Hayes, National Earthquake Hazards Reduction Program Director, National Institute of Standards and Technology, 100 Bureau Drive, Mail Stop 8604, Gaithersburg, Maryland 20899–8604. Dr. Hayes' e-mail address is *jack.hayes@nist.gov* and his phone number is (301) 975–5640.

SUPPLEMENTARY INFORMATION: The Committee was established in accordance with the requirements of Section 103 of the NEHRP Reauthorization Act of 2004 (Pub. L. 108–360). The Committee is composed of 12 members appointed by the Director of NIST, who were selected for their technical expertise and experience, established records of distinguished professional service, and their knowledge of issues affecting the National Earthquake Hazards Reduction Program. The Committee assesses:

- Trends and developments in the science and engineering of earthquake hazards reduction;
- The effectiveness of NEHRP in performing its statutory activities (improved design and construction methods and practices; land use controls and redevelopment; prediction techniques and early-warning systems; coordinated emergency preparedness plans; and public education and involvement programs);
- Any need to revise NEHRP; and
- The management, coordination, implementation, and activities of NEHRP.

Background information on NEHRP and the Advisory Committee is available at *http://nehrp.gov/.*

Pursuant to the Federal Advisory Committee Act, 5 U.S.C. App., notice is hereby given that the ACEHR will meet on Tuesday, November 8, 2011 from 8:30 a.m. to 5 p.m. and Wednesday, November 9, 2011, from 8:30 a.m. to 4 p.m. The meeting will be held at the U.S. Department of Commerce, Herbert C. Hoover Building, Room 4830, 1401 Constitution Ave., NW., Washington, DC 20230. The primary purposes of this meeting are to discuss the relationship of Presidential Policy Directive/PPD–8:

National Preparedness to NEHRP activities, to review the conclusions of the National Research Council Report on National Earthquake Resilience, and to review NEHRP agency updates on their latest activities. The agenda may change to accommodate Committee business. The final agenda will be posted on the NEHRP Web site at *http://nehrp.gov/.*

Individuals and representatives of organizations who would like to offer comments and suggestions related to the Committee's affairs are invited to request a place on the agenda. On Wednesday, November 9, 2011, approximately one-half hour will be reserved near the conclusion of the meeting for public comments, and speaking times will be assigned on a first-come, first-serve basis. The amount of time per speaker will be determined by the number of requests received, but is likely to be about 3 minutes each. Questions from the public will not be considered during this period. Speakers who wish to expand upon their oral statements, those who had wished to speak but could not be accommodated on the agenda, and those who were unable to attend in person are invited to submit written statements to the ACEHR, National Institute of Standards and Technology, 100 Bureau Drive, MS 8604, Gaithersburg, Maryland 20899–8604, via fax at (301) 975–4032, or electronically by e-mail to *info@nehrp.gov.*

All visitors to the U.S. Department of Commerce Herbert C. Hoover Building are required to pre-register to be admitted. Anyone wishing to attend this meeting must register by close of business Tuesday, November 1, 2011, in order to attend. Please submit your full name, e-mail address, and phone number to Michelle Harman. Non-U.S. citizens must also submit their country of citizenship, title, and employer/sponsor. Mrs. Harman's e-mail address is *michelle.harman@nist.gov* and her phone number is (301) 975–5324.

Dated: October 7, 2011.

Willie E. May,

Associate Director for Laboratory Programs.

[FR Doc. 2011–26902 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–13–P

DEPARTMENT OF COMMERCE

National Institute of Standards and Technology

National Construction Safety Team Advisory Committee Meeting

AGENCY: National Institute of Standards and Technology, Department of Commerce.

ACTION: Notice of open meeting.

SUMMARY: The National Construction Safety Team (NCST) Advisory Committee (Committee) will meet on Monday, November 7, 2011. The primary purpose of this meeting is to update the Committee on the status of the National Institute of Standards and Technology (NIST) Disaster and Failure Studies Program, the NCST activities within the Program, and NIST studies following recent tornados, wildland-urban interface fires, and earthquakes. The agenda may change to accommodate Committee business. The final agenda will be posted on the NIST Web site at *http://www.nist.gov/el/disasterstudies/ncst.*

DATES: The NCST Committee will meet on Monday, November 7, 2011, from 8:30 a.m. until 5 p.m. The meeting will be open to the public.

ADDRESSES: The meeting will be held in Rooms C103–C106, Advanced Measurement Laboratory (AML) Building (215), National Institute of Standards and Technology (NIST), 100 Bureau Drive, Gaithersburg, Maryland 20899. Please note admittance instructions under the **SUPPLEMENTARY INFORMATION** section of this notice.

FOR FURTHER INFORMATION CONTACT: Eric Letvin, Director, Disaster and Failure Studies Program, 100 Bureau Drive, Mail Stop 8600, Gaithersburg, Maryland 20899–8600. Mr. Letvin's e-mail address is *eric.letvin@nist.gov* and his phone number is (301) 975–5412.

SUPPLEMENTARY INFORMATION: The Committee was established pursuant to Section 11 of the National Construction Safety Team Act (15 U.S.C. 7301 *et seq.*). The Committee is composed of ten members, appointed by the Director of NIST, who were selected for their technical expertise and experience, established records of distinguished professional service, and their knowledge of issues affecting teams established under the NCST Act. The Committee will advise the Director of NIST on carrying out studies of building failures conducted under the authorities of the NCST Act that became law in October 2002 and will review the procedures developed to implement the NCST Act and reports issued under section 8 of the NCST Act. Background information on the NCST Act and information on the NCST Advisory Committee is available at *http://www.nist.gov/el/disasterstudies/ncst.*

Pursuant to the Federal Advisory Committee Act, 5 U.S.C. app., notice is hereby given that the NCST Advisory Committee will meet on Monday, November 7, 2011, at 8:30 a.m. and will adjourn at 5 p.m. The meeting will be open to the public.

The primary purpose of this meeting is to update the Committee on the status of the NIST Disaster and Failure Studies Program, the NCST activities within the Program, and NIST studies following recent tornados, wildland-urban interface fires, and earthquakes. The final agenda will be posted on the NIST Web site at *http://www.nist.gov/el/disasterstudies/ncst.*

Individuals and representatives of organizations who would like to offer comments and suggestions related to items on the Committee's agenda for this meeting are invited to request a place on the agenda. Approximately one-half hour will be reserved for public comments, and speaking times will be assigned on a first-come, first-served basis. The amount of time per speaker will be determined by the number of requests received, but is likely to be 5 minutes each. Questions from the public will not be considered during this period. Speakers who wish to expand upon their oral statements, those who had wished to speak but could not be accommodated on the agenda, and those who were unable to attend in person are invited to submit written statements to the National Construction Safety Team Advisory Committee, National Institute of Standards and Technology, 100 Bureau Drive, MS 8600, Gaithersburg, Maryland 20899–8600, via fax at (301) 975–4032, or electronically by e-mail to *ncstac@nist.gov.*

All those wishing to speak must submit their request by e-mail to the attention of Mr. Eric Letvin, *eric.letvin@nist.gov* by 5 p.m. EST on November 2, 2011.

All visitors to the NIST site are required to pre-register to be admitted. Anyone wishing to attend this meeting must register by close of business Monday, October 31, 2011, in order to attend. Please submit your full name, e-mail address, and phone number to Eric Letvin. Non-U.S. citizens must also submit their country of citizenship, title, and employer/sponsor. Mr. Eric Letvin's e-mail address is *eric.letvin@nist.gov* and his phone number is (301) 975–5412.

Dated: October 11, 2011.

Willie E. May,

Associate Director for Laboratory Programs.

[FR Doc. 2011–26960 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–13–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XA727

Fisheries of the Caribbean, Gulf of Mexico, and South Atlantic; Gulf of Mexico Reef Fish Fishery; South Atlantic Snapper-Grouper Fishery

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Request for designation; request for comments.

SUMMARY: The Gulf of Mexico Fishery Management Council (GMFMC) has proposed to remove Nassau grouper from the fishery management unit in the Fishery Management Plan for Reef Fish Resources of the Gulf of Mexico (Reef Fish FMP). Subsequently, in a September 16, 2011, letter to NMFS, the GMFMC has requested that the Secretary of Commerce (Secretary) designate the SAFMC as the responsible council to manage Nassau grouper throughout the South Atlantic region and the Gulf of Mexico under the FMP for the Snapper-Grouper Fishery of the South Atlantic Region (Snapper-Grouper FMP). The intent of this notice is to solicit public comments concerning this proposed designation.

DATES: Comments must be received no later than 5 p.m., eastern standard time, on November 17, 2011.

ADDRESSES: You may submit comments on the application by any of the following methods:

• *E-mail: Steve.Branstetter@noaa.gov.* Include in the subject line of the e-mail comment the following document identifier: ''NASSAU''.

• *Mail:* Submit written comments to Steve Branstetter, Southeast Regional Office, NMFS, 263 13th Avenue South, St. Petersburg, FL 33701.

The application and related documents are available for review upon written request to any of the above addresses.

FOR FURTHER INFORMATION CONTACT: Steve Branstetter, 727–824–5305; e-mail: *Steve.Branstetter@noaa.gov.*

SUPPLEMENTARY INFORMATION: The GMFMC has submitted a Generic Annual Catch Limits/Accountability Measures Amendment for the GMFMC's Red Drum, Reef Fish, Shrimp, and Coral and Coral Reefs Fishery Management Plans (Generic ACL Amendment) for purposes of review by the Secretary under the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). A Notice of Availability for the Generic ACL Amendment was published in the **Federal Register** on September 26, 2011 (76 FR 59373). As part of this amendment, the GMFMC has selected to remove Nassau grouper from the Reef Fish FMP. This proposed action is based on an October 20, 2010, letter from the SAFMC informing the GMFMC of its willingness to accept responsibility for managing Nassau grouper throughout South Atlantic and Gulf of Mexico (Gulf) Federal waters. The SAFMC currently manages Nassau grouper in its area of jurisdiction through the Snapper-Grouper FMP.

In accordance with section 304(f) of the Magnuson-Stevens Act, on September 16, 2011, the GMFMC formally requested that the Secretary designate the SAFMC as the responsible Council for continued management of the species in Federal waters of the South Atlantic region and to manage the species in the Federal waters of the Gulf.

Currently, the harvest of Nassau grouper is prohibited in Federal waters by regulations implemented through the GMFMC's Reef Fish FMP and the SAFMC's Snapper-Grouper FMP. Additionally, the harvest of Nassau grouper in Florida state waters is prohibited by the applicable Florida regulations. With the approval and implementation of the GMFMC's Generic ACL Amendment, which proposes to remove Nassau grouper from the Reef Fish FMP, all harvesting restrictions for Nassau grouper in Federal waters of the Gulf would be removed. If the SAFMC is designated as the responsible council for the management of Nassau grouper in the Gulf, the SAFMC is expected to extend the prohibition on harvest in the Gulf. Any action to remove the current prohibitions in the Gulf could have a delayed effective date, so that it was implemented simultaneously with SAFMC action to extend the prohibition.

NMFS requests public comment on the GMFMC's request to designate the SAMFC as the responsible council for managing Nassau grouper in both the Gulf and South Atlantic. Public comments will be reviewed and considered prior to NMFS' decision on this request.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 13, 2011.

Steven Thur,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2011–26931 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration (NOAA)

[Docket No: 111003608–1608–01]

Office of Oceanic and Atmospheric Research Draft Strategic Plan

AGENCY: Office of Oceanic and Atmospheric Research (OAR), National Oceanic and Atmospheric Administration NOAA), Department of Department of Commerce (DOC).

ACTION: Notice of availability and request for public comment.

SUMMARY: This notice announces that OAR's draft Strategic Plan (FY12–18) is available for public review and comment. The draft incorporates OAR's mission and vision, and characterizes its goals and objectives over the next six years. These goals and objectives will provide guidance and strategic direction for program and laboratory planning.

DATES: Public comments are due by 5 p.m., EST, November 11, 2011.

ADDRESSES: Public comments must be submitted to *OAR.Plan@noaa.gov.*

The draft document can be found electronically at: *http://www.oar.noaa.gov/aboutus/strategic.html.* Those without computer access can call 301–734–1048 to request a copy of the draft strategic plan and instructions for returning written comments by U.S. Postal Service.

FOR FURTHER INFORMATION CONTACT: The NOAA Strategic Planning Team at *OAR.Plan@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Background

The National Oceanic and Atmospheric Administration (NOAA) completed its Next Generation Strategic Plan (NGSP) in December of 2010. The NGSP outlines NOAA's long-term goals and objectives. The Office of Oceanic and Atmospheric Research, one of five Line Offices within NOAA, has developed its strategic plan in line with the NGSP to ensure the success of the National Oceanic and Atmospheric Administration.

The strategic plan describes OAR's long-term goals along with specific objectives that will be pursued over the

next five years. Each objective will be pursued and evaluated against outcome-oriented performance measures to determine level of progress. The plan emphasizes OAR core competencies and encourages the pursuit of pre-eminent research and science integrity. Ultimately, this plan provides the framework that OAR will use to deliver significant benefits to society while working to advance NOAA's mission of science, service, and stewardship.

Dated: October 12, 2011.

Mark E. Brown,

Chief Financial Officer/Chief Administrative Officer, Office of Oceanic and Atmospheric Research, National Oceanic and Atmospheric Administration.

[FR Doc. 2011–26878 Filed 10–17–11; 8:45 am]

BILLING CODE 3510–KD–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Proposed Information Collection; Comment Request

AGENCY: Corporation for National and Community Service.

ACTION: Notice.

SUMMARY: The Corporation for National and Community Service (the Corporation), as part of its continuing effort to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) (44 U.S.C. Sec. 3506(c)(2)(A)). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirement on respondents can be properly assessed.

Currently, the Corporation is soliciting comments concerning its proposed renewal of the Disaster Response Cooperative Agreement (DRCA) application. The DRCA enables CNCS supported national service organizations to engage members and participants in disaster response efforts to federally declared disasters and to be eligible to be reimbursed for expenses occurred while engaged in such efforts. This document describes eligibility criteria, the nature of disaster deployments, the Corporation's expectations for performance upon selection, and the application process. This agreement is the legal instrument by which organizations can be reimbursed by the Corporation for expenses incurred by the response, when it occurs under authority of a Mission Assignment from FEMA or another agency. Copies of the information collection request can be obtained by contacting the office listed in the addresses section of this notice.

DATES: Written comments must be submitted to the individual and office listed in the **ADDRESSES** section by December 19, 2011.

ADDRESSES: You may submit comments, identified by the title of the information collection activity, by any of the following methods:

(1) *By mail sent to:* Corporation for National and Community Service, Disaster Services, Attention Kelly DeGraff, Senior Advisor, Disaster Services, Room 960, 1201 New York Avenue, NW., Washington, DC 20525.

(2) By hand delivery or by courier to the Corporation's mailroom at Room 8100 at the mail address given in paragraph (1) above, between 9 a.m. and 4 p.m. Eastern Time, Monday through Friday, except Federal holidays.

(3) Electronically through *http://www.regulations.gov*. Individuals who use a telecommunications device for the deaf (TTY–TDD) may call 1–800–833–3722 between 8 a.m. and 8 p.m. Eastern Time, Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Kelly DeGraff (202) 606–6817, or by e-mail at *kdegraff@cns.gov*.

SUPPLEMENTARY INFORMATION: The Corporation is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Corporation, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are expected to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.,* permitting electronic submissions of responses).

Background

The information collected will be used to help CNCS more effectively utilize its deployable resources to meet the needs of disaster affected communities. A better understanding of the participating programs will allow CNCS to match the capabilities of the programs to the needs of the communities and will allow better asset mapping and resource typing. Additionally, the information collected will allow CNCS to conduct better outreach to interested programs by providing them with more information about CNCS disaster procedures, reimbursement requirements, reimbursable expenses covered by the agreement, and support services offered.

Current Action

The Corporation seeks to renew and revise the current information collection. The revisions are intended to streamline the application process and ensure interested programs meet the appropriate programmatic and fiscal requirements to successfully execute mission-assigned activities. Additionally, the collected information will help CNCS best match the capabilities of the programs to the needs of the communities requesting assistance.

The information collection will otherwise be used in the same manner as the existing application. The Corporation also seeks to continue using the current application until the revised application is approved by OMB. The current application is due to expire on March 31, 2012.

Type of Review: Renewal.

Agency: Corporation for National and Community Service.

Title: Disaster Response Cooperative Agreements.

OMB Number: 3045–0133.

Agency Number: None.

Affected Public: Current grantees and Corporation-supported programs.

Total Respondents: 100.

Frequency: Frequency.

Average Time per Response: Averages two hours.

Estimated Total Burden Hours: 200.

Total Burden Cost (capital/startup): None.

Total Burden Cost (operating/maintenance): None.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also become a matter of public record.

Dated: October 11, 2011.

Kelly DeGraff,

Senior Advisor, Disaster Services Unit.

[FR Doc. 2011–26828 Filed 10–17–11; 8:45 am]

BILLING CODE P

DEPARTMENT OF DEFENSE

Department of the Navy

Meeting of the Ocean Research and Resources Advisory Panel

AGENCY: Department of the Navy, DoD.

ACTION: Notice.

SUMMARY: The Ocean Research and Resources Advisory Panel (ORRAP) will hold a regularly scheduled meeting. The meeting will be open to the public.

DATES: The meeting will be held on Wednesday, November 9, 2011 from 8:30 a.m. to 5 p.m. and Thursday, November 10, 2011 from 8:30 a.m. to 2:30 p.m. Members of the public should submit their comments in advance of the meeting to the meeting Point of Contact.

ADDRESSES: The meeting will be held at the Consortium for Ocean Leadership, 1201 New York Avenue, NW., 4th Floor, Washington DC 20005.

FOR FURTHER INFORMATION CONTACT: Dr. Charles L. Vincent, Office of Naval Research, 875 North Randolph Street, Suite 1425, Arlington, VA 22203–1995, telephone 703–696–4118.

SUPPLEMENTARY INFORMATION: This notice of open meeting is provided in accordance with the Federal Advisory Committee Act (5 U.S.C. App. 2). The meeting will include discussions on ocean research, resource management, and other current issues in the ocean science and management communities.

Dated: October 11, 2011.

J.M. Beal,

Lieutenant Commander, Office of the Judge Advocate General, U.S. Navy, Federal Register Liaison Officer.

[FR Doc. 2011–26915 Filed 10–17–11; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF EDUCATION

Notice of Submission for OMB Review

AGENCY: Department of Education.

ACTION: Comment request.

SUMMARY: The Acting Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management, invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995 (Pub. L. 104–13).

DATES: Interested persons are invited to submit comments on or before November 17, 2011.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, Attention: Education Desk Officer, Office of Management and Budget, 725 17th Street, NW., Room 10222, New Executive Office Building, Washington, DC 20503, be faxed to (202) 395–5806 or e-mailed to *oira_submission@omb.eop.gov* with a cc: to *ICDocketMgr@ed.gov.* Please note that written comments received in response to this notice will be considered public records.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. The OMB is particularly interested in comments which: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Dated: October 13, 2011.

Tomakie Washington,

Acting Director, Information Collection Clearance Division, Privacy, Information and Records Management Services Office of Management.

Office of Elementary and Secondary Education

Type of Review: Extension.

Title of Collection: State MEP Director Survey Binational Migrant Education Initiative.

OMB Control Number: 1810–0670.

Agency Form Number(s): N/A.

Frequency of Responses: Annually.

Affected Public: State, Local or Tribal Government.

Total Estimated Number of Annual Responses: 48.

Total Estimated Annual Burden Hours: 60.

Abstract: This survey collects information from State Migrant Education Programs on their participation in the Binational Migrant Education Initiative to serve children who migrate between Mexico and the U.S.

Copies of the information collection submission for OMB review may be accessed from the RegInfo.gov Web site at *http://www.reginfo.gov/public/do/PRAMain* or from the Department's Web site at *http://edicsweb.ed.gov,* by selecting the ''Browse Pending Collections'' link and by clicking on link number 4697. When you access the information collection, click on ''Download Attachments '' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to the Internet address *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection and OMB Control Number when making your request.

Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. 2011–26926 Filed 10–17–11; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Portsmouth

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Portsmouth. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Thursday, November 3, 2011, 6 p.m.

ADDRESSES: Ohio State University, Endeavor Center, 1862 Shyville Road, Piketon, Ohio 45661.

FOR FURTHER INFORMATION CONTACT: Joel Bradburne, Deputy Designated Federal Officer, Department of Energy Portsmouth/Paducah Project Office, Post Office Box 700, Piketon, Ohio 45661; Phone: (740) 897–3822; or email: *Joel.Bradburne@lex.doe.gov.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to make recommendations to DOE–EM and site management in the areas of environmental restoration, waste management and related activities.

Tentative Agenda:

- Call to Order, Introductions, Review of Agenda

- Approval of October Minutes
- Deputy Designated Federal Officer's Comments
- Federal Coordinator's Comments
- Liaisons' Comments
- Presentation
- Ohio University Progress Update
- FLUOR B&W Community Commitment Plan Update, Jerry Schneider
- Administrative Issues:
  - Subcommittee Updates
- Public Comments
- Final Comments
- Adjourn

Public Participation: The meeting is open to the public. The EM SSAB, Portsmouth, welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Joel Bradburne at least seven days in advance of the meeting at the phone number listed above. Written statements may be filed with the Board either before or after the meeting. Individuals who wish to make oral statements pertaining to agenda items should contact Joel Bradburne at the address or telephone number listed above. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comments will be provided a maximum of five minutes to present their comments.

Minutes: Minutes will be available by writing or calling Joel Bradburne at the address and phone number listed above. Minutes will also be available at the following Web site: *http://www.ports-ssab.energy.gov/.*

Issued at Washington, DC, on October 12, 2011.

LaTanya R. Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2011–26886 Filed 10–17–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Advanced Scientific Computing Advisory Committee

AGENCY: Department of Energy, Office of Science.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an open meeting of the Advanced Scientific Computing Advisory Committee (ASCAC). The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Tuesday, November 1, 2011, 9 a.m.–5 p.m. Wednesday, November 2, 2011, 9 a.m.–12 p.m.

ADDRESSES: American Geophysical Union (AGU), 2000 Florida Avenue, NW., Washington, DC 20009

FOR FURTHER INFORMATION CONTACT: Melea Baker, Office of Advanced Scientific Computing Research; SC–21/Germantown Building; U. S. Department of Energy; 1000 Independence Avenue, SW.; Washington, DC 20585–1290; Telephone (301) 903–7486.

SUPPLEMENTARY INFORMATION:

Purpose of the Meeting: The purpose of this meeting is to provide advice and guidance to the Department of Energy on scientific priorities within the field of advanced scientific computing research.

Tentative Agenda Topics:

- View from Washington
- View from Germantown
- Update on Exascale
- Update on ARRA projects
- Report from CSGF subcommittee
- Report from Networking COV
- Early Career technical talks on HPC Reliability, Diffusion on Complex Networks, and Reversible Software Execution Systems
- Report from Applied Math Workshop on Mathematics for the Analysis, Simulation, and Optimization of Complex Systems
- Report from ASCR–BES Workshop on Data Challenges from Next Generation Facilities
- Public Comment (10-minute rule)

Public Participation: The meeting is open to the public. A webcast of this meeting may be available. Please check the website below for updates and information on how to view the meeting. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Melea Baker by telephone at: (301) 903–7486 or by email at: *Melea.Baker@science.doe.gov*. You must make your request for an oral statement at least 5 business days prior to the meeting. Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule.

Minutes: The minutes of this meeting will be available for viewing on the Office of Advanced Scientific Computing Web site at: *http://www.sc.doe.gov/ascr.*

Issued at Washington, DC on October 12, 2011.

LaTanya R. Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2011–26879 Filed 10–17–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

[Case No. CW–021]

Notice of Petition for Waiver of LG Electronics U.S.A., Inc. From the Department of Energy Residential Clothes Washer Test Procedure, and Grant of Interim Waiver

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of petition for waiver, notice of grant of interim waiver, and request for comments.

SUMMARY: This notice announces receipt of and publishes the LG Electronics U.S.A., Inc. (LG) petition for waiver and application for interim waiver from specified portions of the U.S. Department of Energy (DOE) test procedure for determining the energy consumption of clothes washers. Today's notice also grants an interim waiver of the clothes washer test procedure. Through this notice, DOE also solicits comments with respect to the LG petition.

DATES: DOE will accept comments, data, and information with respect to the LG petition until, but no later than November 17, 2011.

ADDRESSES: You may submit comments, identified by case number CW–021, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail:* *AS_Waiver_Requests@ee.doe.gov* Include ''Case No. CW–021'' in the subject line of the message.
- *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J/1000 Independence Avenue, SW., Washington, DC 20585–0121. Telephone: (202) 586–2945. Please submit one signed original paper copy.
- *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy,

Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024. Please submit one signed original paper copy.

Docket: For access to the docket to review the background documents relevant to this matter, you may visit the U.S. Department of Energy, 950 L'Enfant Plaza SW., (Resource Room of the Building Technologies Program), Washington, DC, 20024; (202) 586–2945, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Available documents include the following items: (1) This notice; (2) public comments received; (3) the petition for waiver and application for interim waiver; and (4) prior DOE waivers and rulemakings regarding similar clothes washer products. Please call Ms. Brenda Edwards at the above telephone number for additional information.

FOR FURTHER INFORMATION CONTACT: Dr. Michael G. Raymond, U.S. Department of Energy, Building Technologies Program, Mail Stop EE–2J, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585–0121. Telephone: (202) 586–9611. E-mail: *Michael.Raymond@ee.doe.gov.*

Ms. Elizabeth Kohl, U.S. Department of Energy, Office of the General Counsel, Mail Stop GC–71, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585–0103. Telephone: (202) 586–7796. E-mail: *Elizabeth.Kohl@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

I. Background and Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for Consumer Products Other Than Automobiles, a program covering most major household appliances, which includes the clothes washers that are the focus of this notice.[1] Part B includes definitions, test procedures, labeling provisions, energy conservation standards, and the authority to require information and reports from manufacturers. Further, Part B authorizes the Secretary of Energy to prescribe test procedures that are reasonably designed to produce results which measure energy efficiency, energy use, or estimated operating costs, and that are not unduly burdensome to conduct. (42 U.S.C. 6293(b)(3)) The test procedure for automatic and semi-automatic clothes washers is contained in 10 CFR part 430, subpart B, appendix J1.

The regulations set forth in 10 CFR 430.27 contain provisions that enable a person to seek a waiver from the test procedure requirements for covered consumer products. The Assistant Secretary for Energy Efficiency and Renewable Energy (the Assistant Secretary) will grant a waiver if it is determined that the basic model for which the petition for waiver was submitted contains one or more design characteristics that prevents testing of the basic model according to the prescribed test procedures, or if the prescribed test procedures may evaluate the basic model in a manner so unrepresentative of its true energy consumption characteristics as to provide materially inaccurate comparative data. 10 CFR 430.27(l). Petitioners must include in their petition any alternate test procedures known to the petitioner to evaluate the basic model in a manner representative of its energy consumption. 10 CFR 430.27(b)(1)(iii). The Assistant Secretary may grant the waiver subject to conditions, including adherence to alternate test procedures. 10 CFR 430.27(l). Waivers remain in effect pursuant to the provisions of 10 CFR 430.27(m).

The waiver process also allows the Assistant Secretary to grant an interim waiver from test procedure requirements to manufacturers that have petitioned DOE for a waiver of such prescribed test procedures. 10 CFR 430.27(a)(2). An interim waiver remains in effect for 180 days or until DOE issues its determination on the petition for waiver, whichever is sooner. DOE may extend an interim waiver for an additional 180 days. 10 CFR 430.27(h).

On December 23, 2010, DOE issued enforcement guidance on the application of waivers for large-capacity clothes washers and announced steps to improve the waiver process and refrain from certain enforcement actions. This guidance can be found on DOE's Web site at *http://www.gc.energy.gov/1661.htm.*

II. Application for Interim Waiver and Petition for Waiver

On October 3, 2011, LG's submitted a petition for waiver from the DOE test procedure applicable to automatic and semi-automatic clothes washers set forth in 10 CFR part 430, subpart B, appendix J1. LG requested the waiver because the mass of the test load used in the procedure, which is based on the basket volume of the test unit, is currently not defined for basket sizes greater than 3.8 cubic feet. In its petition, LG seeks a waiver for the specified basic models with capacities greater than 3.8 cubic feet. Table 5.1 of Appendix J1 defines the test load sizes used in the test procedure as linear functions of the basket volume. LG requests that DOE grant a waiver for testing and rating based on a revised Table 5.1. The table is identical to the Table 5.1 found in DOE's clothes washer test procedure Notice of Proposed Rulemaking (NOPR). 75 FR 57556 (September 21, 1010), which was altered slightly (to correct rounding errors) by the supplemental proposed rule issued on July 26, 2011 *http://www.eere.energy.gov/buildings/appliance_standards/residential/pdfs/rcw_tp_snopr.pdf.*

An interim waiver may be granted if it is determined that the applicant will experience economic hardship if the application for interim waiver is denied, if it appears likely that the petition for waiver will be granted, and/or the Assistant Secretary determines that it would be desirable for public policy reasons to grant immediate relief pending a determination of the petition for waiver. (10 CFR 430.27(g)).

DOE has determined that LG's application for interim waiver does not provide sufficient market, equipment price, shipments, and other manufacturer impact information to permit DOE to evaluate the economic hardship LG might experience absent a favorable determination on its application for interim waiver. Previously, however, DOE granted test procedure waivers to Whirlpool (75 FR 69653 (November 15, 2010)), General Electric Company (GE) (75 FR 76968 (December 10, 2010)), Samsung (76 FR 13169 (March 10, 2011), (76 FR 50207 (August 12, 2011)), and Electrolux (76 FR 11440 (March 2, 2011)) for products with capacities larger than currently specified in the test procedure. DOE has also granted previous waivers to LG for similar products. (76 FR 11233, Mar. 1, 2011; 76 FR 21879, Apr. 19, 2011). In these waivers, DOE established an alternate test procedure extending the linear relationship between the maximum test load size and clothes washer container volume up to 6.0 cubic feet, the same test procedure that would be established by adoption of DOE's September 2010 test procedure NOPR and requested by LG in its current and previous petitions. As noted above, DOE published a supplemental notice of proposed rulemaking to adjust the proposed test procedure (specifically, Table 5.1) to correct rounding errors in a supplemental notice of proposed rulemaking issued on July 26, 2011.

[1] For editorial reasons, upon codification in the U.S. Code, part B was re-designated Part A.

The current DOE test procedure specifies test load sizes only for machines with capacities up to 3.8 cubic feet. For the reasons set forth in DOE's September 2010 NOPR, DOE believes that extending the linear relationship between test load size and container capacity to larger capacities is valid. In addition, testing a basic model with a capacity larger than 3.8 cubic feet using the current procedure could evaluate the basic model in a manner so unrepresentative of its true energy consumption as to provide materially inaccurate comparative data. Based on these considerations, and the waivers granted to Whirlpool, GE, Electrolux and Samsung, as well as the previous waivers granted to LG for similar models, it appears likely that the petition for waiver will be granted. As a result, DOE grants an interim waiver to LG for the basic models of clothes washers with container volumes greater than 3.8 cubic feet specified in its petition for waiver, pursuant to 10 CFR 430.27(g). DOE also provides for the use of an alternative test procedure extending the linear relationship between test load size and container capacity, described below. Therefore, *it is ordered that:*

The application for interim waiver filed by LG is hereby granted for the specified LG clothes washer basic models, subject to the specifications and conditions below.

1. LG shall not be required to test or rate the specified clothes washer products on the basis of the test procedure under 10 CFR part 430 subpart B, appendix J1.

2. LG shall be required to test and rate the specified clothes washer products according to the alternate test procedure as set forth in section IV, ''Alternate Test Procedure.''

The interim waiver applies to the following basic model groups:

Model	Brand
WT6001H*	LG.
WT5170H*	LG.
WM3470H***	LG.
WM4070H***	LG.
4153#21#	Kenmore.
4154#21#	Kenmore.

DOE makes decisions on waivers and interim waivers for only those models specifically set out in the petition, not future models that may be manufactured by the petitioner. LG may submit a subsequent petition for waiver and request for grant of interim waiver, as appropriate, for additional models of clothes washers for which it seeks a waiver from the DOE test procedure. In addition, DOE notes that grant of an interim waiver or waiver does not release a petitioner from the certification requirements set forth at 10 CFR part 429.

III. Alternate Test Procedure

EPCA requires that manufacturers use DOE test procedures to make representations about the energy consumption and energy consumption costs of products covered by the statute. (42 U.S.C. 6293(c)) Consistent representations are important for manufacturers to use in making representations about the energy efficiency of their products and to demonstrate compliance with applicable DOE energy conservation standards. Pursuant to its regulations applicable to waivers and interim waivers from applicable test procedures at 10 CFR 430.27, DOE will consider setting an alternate test procedure for LG in a subsequent Decision and Order.

The alternate procedure approved today is intended to allow LG to make valid representations regarding its clothes washers with basket capacities larger than provided for in the current test procedure. This alternate test procedure is based on the expanded Table 5.1 of Appendix J1 that appears in DOE's clothes washer test procedure NOPR. 75 FR 57556 (September 21, 1010), altered slightly to correct rounding errors as specified in DOE's supplemental proposal issued on July 26, 2011.

During the period of the interim waiver granted in this notice, LG shall test its clothes washer basic models according to the provisions of 10 CFR part 430 subpart B, appendix J1, except that the expanded Table 5.1 below shall be substituted for Table 5.1 of appendix J1.

TABLE 5.1—TEST LOAD SIZES

Container volume		Minimum load		Maximum load		Average load	
Cu. ft.	Liter	Lb	Kg	Lb	Kg	Lb	Kg
≥ <	≥ <						
0–0.8	0–22.7	3.00	1.36	3.00	1.36	3.00	1.36
0.80–0.90	22.7–25.5	3.00	1.36	3.50	1.59	3.25	1.47
0.90–1.00	25.5–28.3	3.00	1.36	3.90	1.77	3.45	1.56
1.00–1.10	28.3–31.1	3.00	1.36	4.30	1.95	3.65	1.66
1.10–1.20	31.1–34.0	3.00	1.36	4.70	2.13	3.85	1.75
1.20–1.30	34.0–36.8	3.00	1.36	5.10	2.31	4.05	1.84
1.30–1.40	36.8–39.6	3.00	1.36	5.50	2.49	4.25	1.93
1.40–1.50	39.6–42.5	3.00	1.36	5.90	2.68	4.45	2.02
1.50–1.60	42.5–45.3	3.00	1.36	6.40	2.90	4.70	2.13
1.60–1.70	45.3–48.1	3.00	1.36	6.80	3.08	4.90	2.22
1.70–1.80	48.1–51.0	3.00	1.36	7.20	3.27	5.10	2.31
1.80–1.90	51.0–53.8	3.00	1.36	7.60	3.45	5.30	2.40
1.90–2.00	53.8–56.6	3.00	1.36	8.00	3.63	5.50	2.49
2.00–2.10	56.6–59.5	3.00	1.36	8.40	3.81	5.70	2.59
2.10–2.20	59.5–62.3	3.00	1.36	8.80	3.99	5.90	2.68
2.20–2.30	62.3–65.1	3.00	1.36	9.20	4.17	6.10	2.77
2.30–2.40	65.1–68.0	3.00	1.36	9.60	4.35	6.30	2.86
2.40–2.50	68.0–70.8	3.00	1.36	10.00	4.54	6.50	2.95
2.50–2.60	70.8–73.6	3.00	1.36	10.50	4.76	6.75	3.06
2.60–2.70	73.6–76.5	3.00	1.36	10.90	4.94	6.95	3.15
2.70–2.80	76.5–79.3	3.00	1.36	11.30	5.13	7.15	3.24
2.80–2.90	79.3–82.1	3.00	1.36	11.70	5.31	7.35	3.33
2.90–3.00	82.1–85.0	3.00	1.36	12.10	5.49	7.55	3.42
3.00–3.10	85.0–87.8	3.00	1.36	12.50	5.67	7.75	3.52

TABLE 5.1—TEST LOAD SIZES—Continued

Container volume		Minimum load		Maximum load		Average load	
Cu. ft.	Liter	Lb	Kg	Lb	Kg	Lb	Kg
≥ <	≥ <						
3.10–3.20	87.8–90.6	3.00	1.36	12.90	5.85	7.95	3.61
3.20–3.30	90.6–93.4	3.00	1.36	13.30	6.03	8.15	3.70
3.30–3.40	93.4–96.3	3.00	1.36	13.70	6.21	8.35	3.79
3.40–3.50	96.3–99.1	3.00	1.36	14.10	6.40	8.55	3.88
3.50–3.60	99.1–101.9	3.00	1.36	14.60	6.62	8.80	3.99
3.60–3.70	101.9–104.8	3.00	1.36	15.00	6.80	9.00	4.08
3.70–3.80	104.8–107.6	3.00	1.36	15.40	6.99	9.20	4.17
3.80–3.90	107.6–110.4	3.00	1.36	15.80	7.16	9.40	4.26
3.90–4.00	110.4–113.3	3.00	1.36	16.20	7.34	9.60	4.35
4.00–4.10	113.3–116.1	3.00	1.36	16.60	7.53	9.80	4.45
4.10–4.20	116.1–118.9	3.00	1.36	17.00	7.72	10.00	4.54
4.20–4.30	118.9–121.8	3.00	1.36	17.40	7.90	10.20	4.63
4.30–4.40	121.8–124.6	3.00	1.36	17.80	8.09	10.40	4.72
4.40–4.50	124.6–127.4	3.00	1.36	18.20	8.27	10.60	4.82
4.50–4.60	127.4–130.3	3.00	1.36	18.70	8.46	10.85	4.91
4.60–4.70	130.3–133.1	3.00	1.36	19.10	8.65	11.05	5.00
4.70–4.80	133.1–135.9	3.00	1.36	19.50	8.83	11.25	5.10
4.80–4.90	135.9–138.8	3.00	1.36	19.90	9.02	11.45	5.19
4.90–5.00	138.8–141.6	3.00	1.36	20.30	9.20	11.65	5.28
5.00–5.10	141.6–144.4	3.00	1.36	20.70	9.39	11.85	5.38
5.10–5.20	144.4–147.2	3.00	1.36	21.10	9.58	12.05	5.47
5.20–5.30	147.2–150.1	3.00	1.36	21.50	9.76	12.25	5.56
5.30–5.40	150.1–152.9	3.00	1.36	21.90	9.95	12.45	5.65
5.40–5.50	152.9–155.7	3.00	1.36	22.30	10.13	12.65	5.75
5.50–5.60	155.7–158.6	3.00	1.36	22.80	10.32	12.90	5.84
5.60–5.70	158.6–161.4	3.00	1.36	23.20	10.51	13.10	5.93
5.70–5.80	161.4–164.2	3.00	1.36	23.60	10.69	13.30	6.03
5.80–5.90	164.2–167.1	3.00	1.36	24.00	10.88	13.50	6.12
5.90–6.00	167.1–169.9	3.00	1.36	24.40	11.06	13.70	6.21

Notes: (1) All test load weights are bone dry weights.
(2) Allowable tolerance on the test load weights are ±0.10 lbs (0.05 kg).

IV. Summary and Request for Comments

Through today's notice, DOE announces receipt of LG's petition for waiver from certain parts of the test procedure that apply to clothes washers and grants an interim waiver to LG. DOE is publishing LG's petition for waiver in its entirety pursuant to 10 CFR 430.27(b)(1)(iv). The petition contains no confidential information. The petition includes a suggested alternate test procedure to measure the energy consumption of clothes washers with capacities larger than the 3.8 cubic feet specified in the current DOE test procedure.

DOE solicits comments from interested parties on all aspects of the petition. Pursuant to 10 CFR 430.27(b)(1)(iv), any person submitting written comments to DOE must also send a copy of such comments to the petitioner. The contact information for the petitioner is John I. Taylor, Vice President, Government Relations and Communications, LG Electronics USA, Inc., 1776 K Street, NW., Washington, DC 20006. All submissions received must include the agency name and case number for this proceeding. Submit electronic comments in Microsoft Word, Portable Document Format (PDF), or text (American Standard Code for Information Interchange (ASCII)) file format and avoid the use of special characters or any form of encryption. Wherever possible, include the electronic signature of the author. DOE does not accept telefacsimiles (faxes).

Issued in Washington, DC, on October 11, 2011.

Kathleen Hogan,

Deputy Assistant Secretary for Energy Efficiency, Energy Efficiency and Renewable Energy.

October 3, 2011
The Honorable Henry Kelly
Acting Assistant Secretary, Energy Efficiency and Renewable Energy
United States Department of Energy
Mail Station EE–10
Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585

Re: Petition for Waiver and Application for Interim Waiver, *Test Procedure for Clothes Washers*

Dear Assistant Secretary Kelly:

LG Electronics, Inc. (LG) respectfully submits this Petition for Waiver and Application for Interim Waiver, pursuant to 10 C.F.R. § 430.27, as related to DOE's test procedure for clothes washers. DOE has already granted LG waivers relating to testing of certain models. 76 Fed. Reg. 21879 (April 19, 2011); id. 11228 (March 1, 2011); id. 11233 (March 1, 2011); 75 Fed. Reg. 71680 (Nov. 24, 2010). The current Petition and Application would expand the number of models subject to the grant of a waiver. ***LG requests expedited treatment of the Petition and Application.***

LG is a manufacturer of clothes washers and other products sold worldwide, including in the United States. LG's U.S. operations are LG Electronics USA, Inc., with headquarters at 1000 Sylvan Avenue, Englewood Cliffs, NJ 07632 (tel. 201–816–2000). Its worldwide headquarters are located at LG Twin Towers 20, Yoido-dong, Youngdungpo-gu Seoul, Korea 150–721; (tel. 011–82–2–3777–1114); URL: http.www.LGE.com. LG's principal brands include LG® and OEM brands, including GE® and Kenmore®.

The test procedure under the Energy Policy and Conservation Act (EPCA), 42 U.S.C. § 6291 et seq., provides for

clothes washers to be tested with specified allowable test load sizes. See 10 C.F.R. Pt. 430, Subpt. B, App. Jl, Table 5.1. The largest average load under Table 5.1 is 9.20 lbs. LG believes that it is appropriate for DOE to grant a waiver that would allow for testing and rating of specified models (see Appendix 1 hereto) with larger test loads where the model has a container volume that is greater than the largest volume shown on Table 5.1.

DOE has already granted waivers and/or interim waivers to a number of manufacturers, including LG, Whirlpool, General Electric, Samsung, and Electrolux for testing with larger test loads for specified models with container volumes in excess of 3.8 cubic feet. See, e.g., 76 Fed. Reg. 48149 (Aug. 8, 2011) (Samsung); id. 21879 (April 19, 2011 (LG); id. 21881 (April 19, 2011) (Samsung); id. 13169 (March 10, 2011) (Samsung); id. 11440 (March 2, 2011) (Electrolux); id. 11228 (March 1, 2011) (LG); id. 11233 (March 1, 2011) (LG); 75 Fed. Reg. 81258 (Dec. 27, 2010) (Electrolux); id. 76968 (Dec. 10, 2010) (GE); id. 71680 (Nov. 24, 2010) (LG); id. 57915 (Sept. 23, 2010) (GE); id. 57937 (Sept. 23, 2010) (Samsung); id. 69653 (Nov. 15, 2010) (Whirlpool); id. 76962 (Dec. 10, 2010) (Electrolux); id. 76968 (Dec. 10, 2010) (GE); id. 81258 (Dec. 27, 2010) (Electrolux); 71 Fed. Reg. 48913 (Aug. 22, 2006) (Whirlpool). The Association of Home Appliance Manufacturers (AHAM) has submitted comments to DOE suggesting that the DOE test procedure be amended to provide for testing with loads in excess of those shown in Table 5.1 when testing is done on clothes washers with volumes in excess of 3.8 cubic feet. See AHAM Comments on the Framework Document for Residential Clothes Washers; EERE–2008–BT–STD–0019; RIN 1904–AB90, at Appendix B—AHAM Proposed Changes to J1 Table 5.1 (Oct. 2, 2009). In addition, DOE has issued a Notice of Proposed Rulemaking proposing to amend the DOE test procedure to adopt the AHAM proposed Table 5.1. 75 Fed. Reg. 57556 (Sept. 21, 2010). Further, DOE has issued a guidance document indicating the appropriateness of waivers for testing with larger test loads for clothes washers with volumes in excess of 3.8 cubic feet. DOE, GC Enforcement Guidance on the Application of Waivers and on the Waiver Process (Dec. 23, 2010), at *http://www.gc.energy.gov/documents/LargeCapacityRCW_guidance_22210.pdf.*

LG requests that DOE grant a waiver for testing and rating based on the revised Table 5.1 in Appendix 2 hereto. This is the Table 5.1 as already set forth in the waivers granted to LG for certain models. See 76 Fed. Reg. 21879 (April 19, 2011); id. 11228 (March 1, 2011); id. 11233 (March 1, 2011); 75 Fed. Reg. 71680 (Nov. 24, 2010). The revised Table 5.1 should be applied to LG's testing and rating of other models as specified in Appendix 1 hereto.[1]

The waiver should continue until DOE adopts an applicable amended test procedure.

LG also requests an interim waiver for its testing and rating of the foregoing models. The petition for waiver is likely to be granted, as evidenced not only by its merits, but also because DOE has granted waivers and/or interim waivers to LG, Whirlpool, GE, Samsung, and Electrolux and has proposed a corresponding amendment to its test procedure. Hence, grant of an interim waiver for LG is appropriate.

We would be pleased to discuss this request with DOE and provide further information as needed.

LG requests expedited treatment of the Petition and Application. In that regard, DOE has stated in its December 23, 2010 Enforcement Guidance (supra) that it ''commits to act promptly on waiver requests.'' LG repeated this in its March 7, 2011 notice concerning its certification, compliance and enforcement rule. 76 Fed. Reg. 12422, 12442 (''The Department renews its commitment to act swiftly on waiver requests'').[2] LG appreciates this commitment by DOE.

We hereby certify that all manufacturers of domestically marketed units of the same product type have been notified by letter of this petition and application, copies of which letters are set forth in Appendix 3 hereto.

Sincerely,

John I. Taylor
Vice President
Government Relations and Communications
LG Electronics USA, Inc.
1776 K Street, NW.,
Washington, DC 20006
Phone: 202–719–3490
Fax: 847–941–8177
E-mail: john.taylor@lge.com

Of counsel:

John A. Hodges
Wiley Rein LLP
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E-mail: jhodges@wileyrein.com

APPENDIX 1

The waiver and interim waiver requested herein should apply to testing and rating of the following model series of LG-manufactured clothes washers. Please note that the actual model numbers will vary to account for such factors as year of manufacture, product color, or other features. Nonetheless, they will always have volumes in excess of 3.8 cubic feet.

(In the chart below, ''#'' represents a number; ''*'' represents a letter.)

Model	Brand
WT6001H*	LG
WT5170H*	LG
WM3470H***	LG
WM4070H***	LG
4153#21#	Kenmore
4154#21#	Kenmore

APPENDIX 2

TABLE 5.1—TEST LOAD SIZES

Container volume		Minimum load		Maximum load		Average load	
cu. ft. ≥ <	liter ≥ <	lb	kg	lb	kg	lb	kg
0–0.8	0–22.7	3.00	1.36	3.00	1.36	3.00	1.36
0.80–0.90	22.7–25.5	3.00	1.36	3.50	1.59	3.25	1.47
0.90–1.00	25.5–28.3	3.00	1.36	3.90	1.77	3.45	1.56
1.00–1.10	28.3–31.1	3.00	1.36	4.30	1.95	3.65	1.66
1.10–1.20	31.1–34.0	3.00	1.36	4.70	2.13	3.85	1.75
1.20–1.30	34.0–36.8	3.00	1.36	5.10	2.31	4.05	1.84

[1] All LG models are measured in accordance with DOE's final guidance for measuring clothes container capacity under the test procedure in 10 C.F.R. Part 430, Subpart B, Appendix J1.

[2] DOE goes on to state that ''DOE, as a matter of policy, will refrain from enforcement actions related to a waiver request that is pending with the Department'' Id.

TABLE 5.1—TEST LOAD SIZES—Continued

Container volume		Minimum load		Maximum load		Average load	
cu. ft. ≥ <	liter ≥ <	lb	kg	lb	kg	lb	kg
1.30–1.40	36.8–39.6	3.00	1.36	5.50	2.49	4.25	1.93
1.40–1.50	39.6–42.5	3.00	1.36	5.90	2.68	4.45	2.02
1.50–1.60	42.5–45.3	3.00	1.36	6.40	2.90	4.70	2.13
1.60–1.70	45.3–48.1	3.00	1.36	6.80	3.08	4.90	2.22
1.70–1.80	48.1–51.0	3.00	1.36	7.20	3.27	5.10	2.31
1.80–1.90	51.0–53.8	3.00	1.36	7.60	3.45	5.30	2.40
1.90–2.00	53.8–56.6	3.00	1.36	8.00	3.63	5.50	2.49
2.00–2.10	56.6–59.5	3.00	1.36	8.40	3.81	5.70	2.59
2.10–2.20	59.5–62.3	3.00	1.36	8.80	3.99	5.90	2.68
2.20–2.30	62.3–65.1	3.00	1.36	9.20	4.17	6.10	2.77
2.30–2.40	65.1–68.0	3.00	1.36	9.60	4.35	6.30	2.86
2.40–2.50	68.0–70.8	3.00	1.36	10.00	4.54	6.50	2.95
2.50–2.60	70.8–73.6	3.00	1.36	10.50	4.76	6.75	3.06
2.60–2.70	73.6–76.5	3.00	1.36	10.90	4.94	6.95	3.15
2.70–2.80	76.5–79.3	3.00	1.36	11.30	5.13	7.15	3.24
2.80–2.90	79.3–82.1	3.00	1.36	11.70	5.31	7.35	3.33
2.90–3.00	82.1–85.0	3.00	1.36	12.10	5.49	7.55	3.42
3.00–3.10	85.0–87.8	3.00	1.36	12.50	5.67	7.75	3.52
3.10–3.20	87.8–90.6	3.00	1.36	12.90	5.85	7.95	3.61
3.20–3.30	90.6–93.4	3.00	1.36	13.30	6.03	8.15	3.70
3.30–3.40	93.4–96.3	3.00	1.36	13.70	6.21	8.35	3.79
3.40–3.50	96.3–99.1	3.00	1.36	14.10	6.40	8.55	3.88
3.50–3.60	99.1–101.9	3.00	1.36	14.60	6.62	8.80	3.99
3.60–3.70	101.9–104.8	3.00	1.36	15.00	6.80	9.00	4.08
3.70–3.80	104.8–107.6	3.00	1.36	15.40	6.99	9.20	4.17
3.80–3.90	107.6–110.4	3.00	1.36	15.80	7.16	9.40	4.26
3.90–4.00	110.4–113.3	3.00	1.36	16.20	7.34	9.60	4.35
4.00–4.10	113.3–116.1	3.00	1.36	16.60	7.53	9.80	4.45
4.10–4.20	116.1–118.9	3.00	1.36	17.00	7.72	10.00	4.54
4.20–4.30	118.9–121.8	3.00	1.36	17.40	7.90	10.20	4.63
4.30–4.40	121.8–124.6	3.00	1.36	17.80	8.09	10.40	4.72
4.40–4.50	124.6–127.4	3.00	1.36	18.20	8.27	10.60	4.82
4.50–4.60	127.4–130.3	3.00	1.36	18.70	8.46	10.80	4.91
4.60–4.70	130.3–133.1	3.00	1.36	19.10	8.65	11.00	5.00
4.70–4.80	133.1–135.9	3.00	1.36	19.50	8.83	11.20	5.10
4.80–4.90	135.9–138.8	3.00	1.36	19.90	9.02	11.40	5.19
4.90–5.00	138.8–141.6	3.00	1.36	20.30	9.20	11.60	5.28
5.00–5.10	141.6–144.4	3.00	1.36	20.70	9.39	11.90	5.38
5.10–5.20	144.4–147.2	3.00	1.36	21.10	9.58	12.10	5.47
5.20–5.30	147.2–150.1	3.00	1.36	21.50	9.76	12.30	5.56
5.30–5.40	150.1–152.9	3.00	1.36	21.90	9.95	12.50	5.65
5.40–5.50	152.9–155.7	3.00	1.36	22.30	10.13	12.70	5.75
5.50–5.60	155.7–158.6	3.00	1.36	22.80	10.32	12.90	5.84
5.60–5.70	158.6–161.4	3.00	1.36	23.20	10.51	13.10	5.93
5.70–5.80	161.4–164.2	3.00	1.36	23.60	10.69	13.30	6.03
5.80–5.90	164.2–167.1	3.00	1.36	24.00	10.88	13.50	6.12
5.90–6.00	167.1–169.9	3.00	1.36	24.40	11.06	13.70	6.21

Notes:
(1) All test load weights are bone dry weights.
(2) Allowable tolerance on the test load weights are ± 0.10 lbs (0.05 kg).

APPENDIX 3

[Letters are not included in the published document.]

[FR Doc. 2011–26883 Filed 10–17–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

[Case No. DW–006]

Notice of Petition for Waiver of Miele, Inc. From the Department of Energy Residential Dishwasher Test Procedure, and Grant of Interim Waiver

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of petition for waiver, notice of grant of interim waiver, and request for comments.

SUMMARY: This notice announces receipt of and publishes the Miele, Inc. (Miele) petition for waiver from specified portions of the U.S. Department of Energy (DOE) test procedure for determining the energy consumption of dishwashers. Today's notice also grants an interim waiver of the dishwasher test procedure. Through this notice, DOE also solicits comments with respect to the Miele petition.

DATES: DOE will accept comments, data, and information with respect to the Miele petition until, but no later than November 17, 2011.

ADDRESSES: You may submit comments, identified by case number DW–006, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: AS_Waiver_Requests@ee.doe.gov.* Include the case number [Case No. DW–006] in the subject line of the message.
- *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, Petition for Waiver Case No. DW–006, 1000 Independence Avenue, SW., Washington, DC 20585–0121. Telephone: (202) 586–2945. Please submit one signed original paper copy.
- *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 950 L'Enfant Plaza, SW., Suite 600, Washington, DC 20024. Please submit one signed original paper copy.

Docket: For access to the docket to review the background documents relevant to this matter, you may visit the U.S. Department of Energy, 950 L'Enfant Plaza, SW., (Resource Room of the Building Technologies Program), Washington, DC 20024; (202) 586–2945, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Available documents include the following items: (1) This notice; (2) public comments received; (3) the petition for waiver and application for interim waiver; and (4) prior DOE rulemakings and waivers regarding similar dish washers. Please call Ms. Brenda Edwards at the above telephone number for additional information regarding visiting the Resource Room.

FOR FURTHER INFORMATION CONTACT: Dr. Michael G. Raymond, U.S. Department of Energy, Building Technologies Program, Mail Stop EE–2J, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585–0121. Telephone: (202) 586–9611. E-mail: *Michael.Raymond@ee.doe.gov.*

Ms. Elizabeth Kohl, U.S. Department of Energy, Office of the General Counsel, Mail Stop GC–71, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585–0103. Telephone: (202) 586–7796. E-mail: *Elizabeth.Kohl@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

I. Background and Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA), Public Law 94–163 (42 U.S.C. 6291–6309, as codified) established the Energy Conservation Program for Consumer Products Other Than Automobiles, a program covering most major household appliances, which includes dishwashers.[1] Part B includes definitions, test procedures, labeling provisions, energy conservation standards, and the authority to require information and reports from manufacturers. Further, Part B authorizes the Secretary of Energy to prescribe test procedures that are reasonably designed to produce results which measure energy efficiency, energy use, or estimated operating costs, and that are not unduly burdensome to conduct. (42 U.S.C. 6293(b)(3)) The test procedure for dishwashers is contained in 10 CFR part 430, subpart B, appendix C.

The regulations set forth in 10 CFR part 430.27 contain provisions that enable a person to seek a waiver from the test procedure requirements for covered consumer products. A waiver will be granted by the Assistant Secretary for Energy Efficiency and Renewable Energy (the Assistant Secretary) if it is determined that the basic model for which the petition for waiver was submitted contains one or more design characteristics that prevents testing of the basic model according to the prescribed test procedures, or if the prescribed test procedures may evaluate the basic model in a manner so unrepresentative of its true energy consumption characteristics as to provide materially inaccurate comparative data. 10 CFR part 430.27(l). Petitioners must include in their petition any alternate test procedures known to the petitioner to evaluate the basic model in a manner representative of its energy consumption. 10 CFR part 430.27(b)(1)(iii). The Assistant Secretary may grant the waiver subject to conditions, including adherence to alternate test procedures. 10 CFR part 430.27(l). Waivers remain in effect pursuant to the provisions of 10 CFR part 430.27(m).

The waiver process also allows the Assistant Secretary to grant an interim waiver from test procedure requirements to manufacturers that have petitioned DOE for a waiver of such prescribed test procedures. 10 CFR part 430.27(a)(2) An interim waiver remains in effect for 180 days or until DOE issues its determination on the petition for waiver, whichever is sooner. An interim waiver may be extended for an additional 180 days. 10 CFR part 430.27(h)

[1] For editorial reasons, upon codification in the U.S. Code, Part B was re-designated Part A.

II. Petition for Waiver

On July 19, 2011, Miele filed a petition for waiver and application for interim waiver from the test procedure applicable to dishwashers set forth in 10 CFR part 430, subpart B, appendix C. Miele has designed new dishwashers that run on an electrical supply voltage of 208 volts. The existing test procedure under Title 10 of the Code of Federal Regulations 430.23(c) has provisions for testing at 115 and 240 volts only. The electrical supply voltage of 208 volts prevents testing these dishwashers according to the DOE test procedure. The only modification needed to the test procedure is to provide for testing with a 208 volt electrical supply.

III. Application for Interim Waiver

Miele also requests an interim waiver for particular basic models with integrated water softeners. An interim waiver may be granted if it is determined that the applicant will experience economic hardship if the application for interim waiver is denied, if it appears likely that the petition for waiver will be granted, and/or the Assistant Secretary determines that it would be desirable for public policy reasons to grant immediate relief pending a determination of the petition for waiver. (10 CFR part 430.27(g))

DOE determined that Miele's application for interim waiver does not provide sufficient market, equipment price, shipments, and other manufacturer impact information to permit DOE to evaluate the economic hardship Miele might experience absent a favorable determination on its application for interim waiver. DOE understands, however, that the current test procedure does not allow for testing a dishwasher with a 208 volt electrical supply and that the simple addition of a provision for testing with a 208 volt electrical supply is the only modification necessary to allow Miele's product to be tested.

This petition for waiver is likely to be successful because it requests a simple change which will allow testing of any dishwasher with a 208 volt supply. This change has no other effect on testing or rating. As a result, DOE grants Miele's application for interim waiver. Therefore, Miele shall be required to test its dishwasher model G7856–208V according to the existing DOE test procedure at 10 CFR 430, subpart B, appendix C, with the modification set forth below:

Under appendix C, add the following section 2.2.3:

2.2.3 *Dishwashers that operate with an electrical supply of 208 volts.* Maintain the electrical supply to the dishwasher at 208 volts ±2 percent and within 1 percent of its nameplate frequency as specified by the manufacturer.

DOE makes decisions on waivers and interim waivers for only those models specifically set out in the petition, not future models that may be manufactured by the petitioner. Miele may submit a new or amended petition for waiver and request for grant of interim waiver, as appropriate, for additional models of dishwashers for which it seeks a waiver from the DOE test procedure. Grant of an interim waiver does not release a petitioner from the certification requirements set forth at 10 CFR part 429.

IV. Summary and Request for Comments

Through today's notice, DOE announces receipt of Miele's petition for waiver from certain parts of the test procedure that apply to dishwashers. DOE is publishing Miele's petition for waiver in its entirety pursuant to 10 CFR part 430.27(b)(1)(iv). The petition contains no confidential information. The petition includes a suggested alternate test procedure which is to include a provision for a 208 volt electrical supply voltage.

DOE solicits comments from interested parties on all aspects of the petition. Pursuant to 10 CFR 430.27(b)(1)(iv), any person submitting written comments to DOE must also send a copy of such comments to the petitioner. The contact information for the petitioner is Mr. Steve Polinski, Senior Manager Regulatory Affairs, Miele Incorporated, 9 Independence Way, Princeton, NJ 08540. All submissions received must include the agency name and case number for this proceeding. Submit electronic comments in WordPerfect, Microsoft Word, Portable Document Format (PDF), or text (American Standard Code for Information Interchange (ASCII)) file format and avoid the use of special characters or any form of encryption. Wherever possible, include the electronic signature of the author. DOE does not accept telefacsimiles (faxes).

Issued in Washington, DC, on October 11, 2011.

Kathleen Hogan,

Deputy Assistant Secretary for Energy Efficiency, Office of Technology Development, Energy Efficiency and Renewable Energy.

August 4, 2011
The Honorable Catherine Zoi
Assistant Secretary, Energy Efficiency and Renewable Energy
U.S. Department of Energy
Maile Station EE–10
1000 Independence Avenue, SW.,
Washington, DC 20585

Re: Application for Interim Waiver and Petition for Waiver, 10 CFR 430 Subpart B, Appendix C—Uniform Test Method for Measuring Energy Consumption of Dishwashers

Dear Assisant Secretary Zoi,

Miele Inc is submitting this Application for Interim Waiver and Petition for Waiver of the Department of Energy's Test procedure pursuant to 10 CFR 430.27, to the Department of Energy concerning the test procedure found in 10 CFR 430, Subpart B, Appendix C for measuring energy consumption of dishwashers specifically the Miele G7856–208V.

The request for this waiver is focused on the testing voltages specified in the existing test procedure found in Section 2.2.

2.2.1 Dishwashers that operate with an electrical supply of 115 volts. Maintain the electrical supply to the dishwasher at 115 Volts ±2 percent and within 1 percent of the nameplate frequency as specified by the manufacturer.

2.2.2 Dishwashers that operate with an electrical supply of 240 Volts. Maintain the electrical supply to the dishwasher at 240 volts ±2 percent and within 1 percent of its nameplate frequency as specified by the manufacturer.

Currently there is no provision to test dishwashers at 208 Volts.

There are many instances where only 208 Volts is provided to the consumer. Dishwashers rated at 240 Volts would not allow the proper operation of a dishwasher when connected to a 208 Volt supply. To achieve the data plate rating, appropriate voltage components are used in the design of the 208 Volt dishwashers.

The proposed test procedure would allow for a variation in electrical supply voltage to 208 Volts based on the electrical safety test data plate rating. In the case of the G7856–208V, a rating of 208 Volts ±2 percent and within 1 percent of its nameplate frequency as specified by the manufacturer would be used to perform the energy test.

Miele requests immediate relief by grant of the proposed interim waiver, justified by the following reasons:

Economic Hardship. Since the Miele 208V dishwasher is intended to be sold in applications where 240Volts is not made available to the consumer, denial of this Application for Interim Waiver and Petition for Waiver would eliminate the possibility of high performance dishwasher sales where a compatible voltage is not present.

Public Policy Merits. The public policy benefits of encouraging business success and fostering innovation in high performance dishwasher design are additional reasons for prompt approval of the requested interim waiver.

We hereby certify that all dishwasher manufacturers of domestically-marketed units known to Miele Appliances, Inc. have been notified by letter of this application, copies of which are attached

Thank you for your timely attention to this Application for Interim Waiver and Petition for Waiver.

Best regards,

Steve Polinski
Senior Manager Regulatory Affairs
Miele Incorporated
9 Independence Way
Princeton, New Jersey 08540
SPolinski@MieleUSA.com
Phone: 609 419 9898

[FR Doc. 2011–26884 Filed 10–17–11; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP12–7–000.

Applicants: Rockies Express Pipeline LLC.

Description: Rockies Express Pipeline LLC submits tariff filing per 154.204: Negotiated Rate 2011–10–05 Concord to be effective 10/6/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5043.

Comment Date: 5 p.m. Eastern Time on Monday, October 17, 2011.

Docket Numbers: RP12–8–000.

Applicants: Midcontinent Express Pipeline LLC.

Description: Midcontinent Express Pipeline LLC submits tariff filing per 154.204: Tariff Clean Up Filing to be effective 11/5/2011.

Filed Date: 10/06/2011.

Accession Number: 20111006–5079.

Comment Date: 5 p.m. Eastern Time on Tuesday, October 18, 2011.

Docket Numbers: RP12–9–000.

Applicants: Natural Gas Pipeline Company of America LLC.

Description: Penalty Revenue Crediting Report of Natural Gas Pipeline Company of America LLC.

Filed Date: 10/07/2011.

Accession Number: 20111007–5043.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP12–10–000.

Applicants: Trunkline Gas Company, LLC.

Description: Trunkline Gas Company, LLC submits tariff filing per 154.204: Negotiated Rates Filing, to be effective 10/8/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5085.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP12–11–000.

Applicants: Gas Transmission Northwest LLC.

Description: Gas Transmission Northwest LLC submits tariff filing per 154.204, to be effective 6/27/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5099.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP12–12–000.

Applicants: Trailblazer Pipeline Company LLC.

Description: Trailblazer Pipeline Company LLC submits tariff filing per 154.204: Negotiated Rate Filing—Shell Energy to be effective 9/1/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5113.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP12–13–000.

Applicants: Williston Basin Interstate Pipeline Company.

Description: Williston Basin Interstate Pipeline Company submits tariff filing per 154.204: New Injection/Withdrawal Language to be effective 11/10/2011.

Filed Date: 10/11/2011.

Accession Number: 20111011–5010.

Comment Date: 5 p.m. Eastern Time on Monday, October 24, 2011.

Docket Numbers: CP11–550–000.

Applicants: Colorado Interstate Gas Company.

Description: Petition to Amend Certificate Order of Colorado Interstate Gas Company.

Filed Date: 09/23/2011.

Accession Number: 20110923–5103.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP11–2456–001.

Applicants: Empire Pipeline, Inc.

Description: Empire Pipeline, Inc. submits tariff filing per 154.205(b): Changes—Tioga Expansion Project—Update to be effective 10/28/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5062.

Comment Date: 5 p.m. Eastern Time on Monday, October 17, 2011.

Docket Numbers: RP10–1018–002.

Applicants: Paiute Pipeline Company.

Description: Paiute Pipeline Company submits tariff filing per: Place Facilities into Service re: Docket CP10–41 to be effective N/A.

Filed Date: 10/07/2011.

Accession Number: 20111007–5058.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP11–2577–001.

Applicants: Dominion Transmission, Inc.

Description: Dominion Transmission, Inc. submits tariff filing per 154.205(b): DTI—Abandonment of X–71 and X–72 Amendment to be effective 11/1/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5028.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP11–2652–001.

Applicants: ANR Pipeline Company.

Description: ANR Pipeline Company submits tariff filing per 154.205(b): Amended Filing to RP11–2652 to be effective 11/1/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5072.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 19, 2011.

Docket Numbers: RP11–2638–001.

Applicants: Midwestern Gas Transmission Company.

Description: Midwestern Gas Transmission Company submits tariff filing per 154.205(b): Amendment to Non-Conforming Agreements (BP et al) to be effective 11/1/2011.

Filed Date: 10/06/2011.

Accession Number: 20111006–5121.

Comment Date: 5 p.m. Eastern Time on Tuesday, October 18, 2011.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, and service can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 11, 2011.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–26862 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #2

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER11–3262–004.

Applicants: Trans Bay Cable LLC.

Description: Trans Bay Cable LLC submits tariff filing per 35: Withdrawing Filing 168 and resubmitting Filing 152 to be effective 6/30/2011.

Filed Date: 10/06/2011.

Accession Number: 20111006–5059.

Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER11–4296–001.

Applicants: ITC Midwest LLC.

Description: ITC Midwest LLC submits tariff filing per 35.17(b): Amendment to Filing to be effective 10/12/2011.

Filed Date: 10/06/2011.

Accession Number: 20111006–5048.

Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–23–000.

Applicants: Sierra Pacific Power Company.

Description: Sierra Pacific Power Company submits tariff filing per 35.13(a)(2)(i): Rate Schedule No. 27—Annual BPA–GTA Update 2011 to be effective 11/1/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5000.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–34–000.

Applicants: Xcel Energy Services Inc., Northern States Power Company, a Wisconsin corporation.

Description: Report of Xcel Energy Services Inc.

Filed Date: 10/05/2011.

Accession Number: 20111005–5117.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–35–000.

Applicants: Choice Energy, LLC.
Description: Choice Energy, LLC submits tariff filing per 35.1: Baseline Filing to be effective 10/6/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5057.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–36–000.
Applicants: PacifiCorp.
Description: PacifiCorp filing of Storage Agreements.
Filed Date: 10/04/2011.
Accession Number: 20111004–5184.
Comment Date: 5 p.m. Eastern Time on Tuesday, October 25, 2011.

Docket Numbers: ER12–37–000.
Applicants: Smart Papers Holdings LLC.
Description: Smart Papers Holdings LLC submits tariff filing per 35.1: Smart Papers Holdings LLC MBR to be effective 10/6/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5076.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Take notice that the Commission received the following electric securities filings:

Docket Numbers: ES11–49–000.
Applicants: Louisville Gas & Electric Company.
Description: Amendment to Application of Louisville Gas and Electric Company under ES11–49.
Filed Date: 10/05/2011.
Accession Number: 20111005–5114.
Comment Date: 5 p.m. Eastern Time on Monday, October 17, 2011.

Docket Numbers: ES12–2–000.
Applicants: KCP&L Greater Missouri Operations Company.
Description: Application for Authorization of Issuance of Long-Term Debt Securities Under Section 204 of the Federal Power Act of KCP&L Greater Missouri Operations Company.
Filed Date: 10/06/2011.
Accession Number: 20111006–5050.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Take notice that the Commission received the following public utility holding company filings:

Docket Numbers: PH12–1–000.
Applicants: South Jersey Industries, Inc.
Description: Notice of Material Change in Facts of South Jersey Industries, Inc.
Filed Date: 10/05/2011.
Accession Number: 20111005–5119.
Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 6, 2011.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–26865 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER04–157–033; ER04–714–022; EL05–89–011.
Applicants: Bangor Hydro-Electric Company; Florida Power & Light Company New England.
Description: Report/Form of Northeast Utilities Service Company.
Filed Date: 10/06/2011.
Accession Number: 20111006–5150.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER10–2288–005.
Applicants: Optim Energy Marketing, LLC.
Description: Notice of Non-Material Change in Status of Optim Energy Marketing, LLC.
Filed Date: 10/06/2011.
Accession Number: 20111006–5105.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER11–3277–002.
Applicants: Sky River LLC.
Description: Sky River LLC submits tariff filing per 35: Sky River LLC Open Access Transmission Tariff Compliance Filing to be effective 10/7/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5111.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER11–4443–001.
Applicants: AK Electric Supply, LLC.
Description: AK Electric Supply, LLC submits tariff filing per 35: Amended MBR Filing to be effective 9/6/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5119.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER11–4618–002.
Applicants: White Pine Electric Power.
Description: White Pine Electric Power submits tariff filing per 35: Market-Based Rate Tariff Compliance to be effective 9/23/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5123.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–38–000.
Applicants: Wisconsin Electric Power Company.
Description: Wisconsin Electric Power Company submits tariff filing per 35.13(a)(2)(iii: Wisconsin Electric Rate Schedule No. 129 Letter of Concurrence to be effective 10/4/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5120.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–39–000.
Applicants: Flat Ridge Wind Energy, LLC.
Description: Flat Ridge Wind Energy, LLC submits tariff filing per 35.13(a)(2)(iii: Updated Market-Based Rate Tariff Update to be effective 12/5/2011.
Filed Date: 10/06/2011.
Accession Number: 20111006–5122.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–40–000.
Applicants: GDF SUEZ Energy Resources NA, Inc.
Description: Refund Report of GDF SUEZ Energy Resources NA, Inc.
Filed Date: 10/06/2011.
Accession Number: 20111006–5154.
Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

Docket Numbers: ER12–41–000.
Applicants: ITC Midwest LLC.
Description: ITC Midwest LLC submits tariff filing per 35.13(a)(2)(iii: Filing of Joint Use Pole Agreements to be effective 12/7/2011.
Filed Date: 10/07/2011.
Accession Number: 20111007–5025.
Comment Date: 5 p.m. Eastern Time on Friday, October 28, 2011.

Docket Numbers: ER12–42–000.
Applicants: Smart Papers Holdings LLC.
Description: Smart Papers Holdings LLC submits tariff filing per 35.1: Smart

Papers Holdings LLC MBR to be effective 10/6/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5032.

Comment Date: 5 p.m. Eastern Time on Friday, October 28, 2011.

Docket Numbers: ER12–43–000.

Applicants: Wisconsin Electric Power Company.

Description: Wisconsin Electric Power Company submits tariff filing per 35.13(a)(2)(iii: Wisconsin Electric Rate Schedule No. 128 Letter of Concurrence to be effective 10/4/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5034.

Comment Date: 5 p.m. Eastern Time on Friday, October 28, 2011.

Docket Numbers: ER12–44–000.

Applicants: Public Service Company of New Mexico.

Description: Public Service Company of New Mexico submits tariff filing per 35.12: OATT Service Agreement No. 341 to be effective 12/7/2011.

Filed Date: 10/07/2011.

Accession Number: 20111007–5050.

Comment Date: 5 p.m. Eastern Time on Friday, October 28, 2011.

Take notice that the Commission received the following electric securities filings:

Docket Numbers: ES12–3–000.

Applicants: National Grid USA.

Description: Application of National Grid USA on Behalf of Certain of its Subsidiaries and Affiliates for Authorization to Issue Securities under Section 204 of the Federal Power Act.

Filed Date: 10/06/2011.

Accession Number: 20111006–5147.

Comment Date: 5 p.m. Eastern Time on Thursday, October 27, 2011.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 07, 2011.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–26864 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER11–4042–001.

Applicants: The Detroit Edison Company.

Description: The Detroit Edison Company submits tariff filing per 35: FERC Electric Rate Schedule No. 43—SFA Compliance Filing to be effective 9/28/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5038.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER11–4469–001.

Applicants: Columbia Utilities Power, LLC.

Description: Columbia Utilities Power, LLC submits tariff filing per 35: Columbia Utilities Power FERC Electric Tariff to be effective 9/8/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5029.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–23–000.

Applicants: Sierra Pacific Power Company.

Description: Sierra Pacific Power Company submits tariff filing per 35.13(a)(2)(i): Rate Schedule No. 27—Annual BPA–GTA Update 2011 to be effective 11/1/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5000.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–25–000.

Applicants: Southwest Power Pool, Inc.

Description: Southwest Power Pool, Inc. submits tariff filing per 35.13(a)(2)(iii: Implement Formula Rate Updates for GRDA, LES and OPPD to be effective 8/1/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5019.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–26–000.

Applicants: New York Independent System Operator, Inc.

Description: New York Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: NYISO proposed tariff revisions regarding dispute resolution provisions to be effective 12/4/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5048.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–27–000.

Applicants: New York Independent System Operator, Inc.

Description: New York Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: NYISO proposed ISO Agreement revisions regarding dispute resolution provisions to be effective 12/4/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5052.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–28–000.

Applicants: Southwest Power Pool, Inc.

Description: Southwest Power Pool, Inc. submits tariff filing per 35.13(a)(2)(iii: Implement Formula Rate Updates for Midwest Energy, Inc. to be effective 9/1/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5068.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–29–000.

Applicants: PPL EnergyPlus, LLC.

Description: PPL EnergyPlus, LLC submits tariff filing per 35: PPL EnergyPlus Compliance Tariff to be Effective March 1, 2010 to be effective 9/30/2010.

Filed Date: 10/05/2011.

Accession Number: 20111005–5070.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–30–000.

Applicants: BlueStar Energy Services Inc.

Description: BlueStar Energy Services Inc. submits tariff filing per 35.1: Baseline FERC Electric MBR Tariff Filing to be effective 10/5/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5075.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–31–000.

Applicants: Southern California Edison Company.

Description: Southern California Edison Company submits tariff filing per 35.13(a)(2)(iii: SGIA WDT SERV SCE–SunEdison 1351 Railroad Ave. Corona Roof Top Solar Project to be effective 10/6/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5082.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–32–000.

Applicants: Silver State Solar Power North, LLC.

Description: Silver State Solar Power North, LLC submits tariff filing per 35.12: Silver State North Initial Market-Based Rate Tariff to be effective 11/15/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5092.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

Docket Numbers: ER12–33–000.

Applicants: Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Midwest Independent Transmission System Operator, Inc.

Description: Duke Energy Ohio, Inc. submits tariff filing per 35.13(a)(2)(iii: 10–05–11 DEO/DEK Exit Fee Agreement to be effective 12/31/2011.

Filed Date: 10/05/2011.

Accession Number: 20111005–5093.

Comment Date: 5 p.m. Eastern Time on Wednesday, October 26, 2011.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 6, 2011.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–26861 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP06–275–003]

Big Sandy Pipeline, LLC; Notice of Cost and Revenue Study

Take notice that on April 8, 2011, Big Sandy Pipeline, LLC filed its cost and revenue study in compliance with the Commission's November 15, 2006 Order Issuing Certificate.

Any person desiring to protest this filing must file in accordance with Rule 211 of the Commission's Rules of Practice and Procedure (18 CFR 385.211). Protests to this filing will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Such protests must be filed on or before the date as indicated below. Anyone filing a protest must serve a copy of that document on all the parties to the proceeding.

The Commission encourages electronic submission of protests in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERC OnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time Friday, October 21, 2011.

Dated: October 11, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–26846 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–32–000]

Silver State Solar Power North LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Silver State Solar Power North, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization under 18 CFR part 34 of future issuances of securities and assumptions of liability is October 31, 2011.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed dockets(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 11, 2011.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2011–26863 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Sunshine Act Meeting Notice

October 13, 2011.

The following notice of meeting is published pursuant to section 3(a) of the

government in the Sunshine Act (Pub. L. No. 94–409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING: Federal Energy Regulatory Commission.

DATE AND TIME: October 20, 2011, 10 a.m.

PLACE: Room 2C, 888 First Street, NE., Washington, DC 20426.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

* NOTE—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Kimberly D. Bose, Secretary, Telephone (202) 502–8400.

For a recorded message listing items struck from or added to the meeting, call (202) 502–8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's Web site at *http://www.ferc.gov* using the eLibrary link, or may be examined in the Commission's Public Reference Room.

974TH—MEETING, REGULAR MEETING, OCTOBER 20, 2011, 10 A.M.

Item No.	Docket No.	Company
	ADMINISTRATIVE	
A–1	AD02–1–000	Agency Business Matters.
A–2	AD02–7–000	Customer Matters, Reliability, Security and Market Operations.
A–3	AD05–9–001	Winter 2011–12 Market Reliability Assessment.
	ELECTRIC	
E–1	RM11–17–000	Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators.
E–2	RM11–18–000	Transmission Planning Reliability Standards.
E–3	RM11–20–000	Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards.
E–4	RR11–7–000	North American Electric Reliability Corporation.
E–5	OMITTED	
E–6	RD11–9–000	North American Electric Reliability Coporation.
E–7	RD11–8–000	North American Electric Reliability Corporation.
E–8	NP10–160–001	North American Electric Reliability Corporation.
E–9	EL05–121–006	PJM Interconnection, L.L.C.
E–10	ER10–1401–001, ER10–2191–001, ER11–2705–000 ER11–2705–001.	California Independent System Operator Corporation
	EL10–76–001	Green Energy Express LLC and 21st Century Transmission Holdings, LLC.
E–11	ER10–1791–001, ER10–1791–002	Midwest Independent Transmission System Operator, Inc.
E–12	ER10–1069–001	Southwest Power Pool, Inc.
E–13	ER11–3627–000	Southwest Power Pool, Inc.
E–14	ER11–4358–000	Southern California Edison Company.
	ER11–4512–000	California Independent System Operator Corporation.
E–15	ER11–4375–000	City of Pasadena, California.
E–16	ER11–3735–000	Puget Sound Energy, Inc.
E–17	ER11–3881–000, ER11–3881–001	New York Independent System Operator, Inc.
E–18	ER11–3891–000	ISO New England Inc.
E–19	ER09–1050–006, ER09–1192–005, ER11–121–000.	Southwest Power Pool, Inc.
E–20	EL11–54–000	Buckeye Power, Inc. v. American Transmission Systems, Incorporated.
E–21	ER11–2895–000, ER11–2895–001, ER11–3585–000.	Duke Energy Carolinas, LLC.
E–22	EL11–30–000	E.ON Climate & Renewables North America, LLC v. Midwest Independent Transmission System Operator, Inc.
E–23	ER10–1706–001, ER10–1706–002	California Independent System Operator Corporation.
E–24	ER03–563–067	Devon Power LLC.
E–25	EL01–88–007	Louisiana Public Service Commission v. Entergy Services, Inc.
E–26	EL01–88–008	Louisiana Public Service Commission v. Entergy Services, Inc.
E–27	EL09–50–000	Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, L.L.C., Entergy Arkansas, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc.
E–28	RM11–7–000, AD10–11–000	Frequency Regulation Compensation in the Organized Wholesale Power Markets.
	GAS	
G–1	AC10–22–004, AC10–22–000, AC10–22–001, AC10–22–003.	Colorado Interstate Gas Company.
G–2	RP11–60–002, RP11–60–003	Southern Natural Gas Company.
G–3	RP11–1538–001	Natural Gas Supply Association, American Forest and Paper Association, American Public Gas Association, Independent Petroleum Association of America, and Process Gas Consumers Group.
	HYDRO	
H–1	P–12626–003, P–12717–003	Northern Illinois Hydropower, LLC.
H–2	P–2677–020	City of Kaukauna, Wisconsin.

974TH—MEETING, REGULAR MEETING, OCTOBER 20, 2011, 10 A.M.—Continued

Item No.	Docket No.	Company
H–3	P–14105–000	Kahawai Power 4, LLC.
	P–14203–000	Kekaha Ditch Hydro, LLC.
H–4	P–9202–177	Upper Yampa Water Conservancy District.
H–5	P–2210–212	Appalachian Power Company.
	CERTIFICATES	
C–1	CP11–128–000, CP11–133–000	National Fuel Gas Supply Corporation Tennessee Gas Pipeline Company.
C–2	CP11–1–001, RP11–2201–000	Pine Prairie Energy Center, LLC.

Kimberly D. Bose,

Secretary.

A free webcast of this event is available through *http://www.ferc.gov.* Anyone with Internet access who desires to view this event can do so by navigating to *http://www.ferc.gov*'s Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit *http://www.CapitolConnection.org* or contact Danelle Springer or David Reininger at 703–993–3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

[FR Doc. 2011–26983 Filed 10–14–11; 11:15 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP12–2–000]

Williston Basin Interstate Pipeline Company; Notice of Request Under Blanket Authorization

Take notice that on October 3, 2011 Williston Basin Interstate Pipeline Company (Williston Basin), 1250 West Century Avenue, Bismarck, North Dakota 58503, filed in Docket No. CP12–2–000, a Prior Notice request pursuant to Sections 157.205 and 157.208 of the Commission's Regulations under the Natural Gas Act for authorization to abandon certain natural gas transmission facilities located in Dawson County, Montana. Specifically, Williston Basin proposes to abandon a 10.325 mile looped portion of its 12-inch diameter Cabin Creek to Williston line. Williston Basin intends to pig, purge, cap at each end and abandon the pipeline in-place and asserts that the abandonment of the pipeline and facilities is necessary due to the poor condition of the pipeline, all as more fully set forth in the application which is on file with the Commission and open to public inspection. The filing may also be viewed on the Web at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (866) 208–3676 or TTY, (202) 502–8659.

Any questions regarding this Application should be directed to Keith A. Tiggelar, Director of Regulatory Affairs, Williston Basin Interstate Pipeline Company, 1250 West Century Avenue, Bismark, North Dakota 58503, or call (701) 530–1560 or by e-mail *keith.tiggelaar@wbip.com.*

Any person may, within 60 days after the issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention. Any person filing to intervene or the Commission's staff may, pursuant to section 157.205 of the Commission's Regulations under the NGA (18 CFR 157.205) file a protest to the request. If no protest is filed within the time allowed therefore, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to section 7 of the NGA.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commenter's will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with he Commission's environmental review process. Environmental commenter's will not be required to serve copies of filed documents on all other parties. However, the non-party commentary, will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and ill not have the right to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests, and interventions via the Internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site (*http://www.ferc.gov*) under the ''e-Filing'' link.

Dated: October 11, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–26847 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Commission Staff Attendance

The Federal Energy Regulatory Commission hereby gives notice that members of the Commission's staff may attend the following meetings related to the transmission planning activities of ISO New England Inc.:

Order 1000: NEPOOL Transmission Committee

October 17, 2011, 1 p.m.–4 p.m., Local Time.

December 1, 2011, 1 p.m.–4 p.m., Local Time.

The above-referenced meetings will be held at: DoubleTree by Hilton Hotel, 5400 Computer Drive, Westborough, Massachusetts 01581.

The above-referenced meetings are open to stakeholders.

Further information may be found at *http://www.iso-ne.com*.

The discussions at the meetings described above may address matters at issue in the following proceedings:

Docket No. ER11–4021, *ISO New England Inc., Northeast Utilities Service Company*.

Docket No. ER11–4022, *ISO New England Inc., Northeast Utilities Service Company*.

Docket No. ER11–4023, *ISO New England Inc., Northeast Utilities Service Company*.

Docket No. ER11–49, *National Grid Transmission Services Corporation*.

For more information, contact William Lohrman, Office of Energy Market Regulation, Federal Energy Regulatory Commission at (202) 502–8070 or *william.lohrman@ferc.gov*.

Dated: October 11, 2011.

Kimberly D. Bose,

Secretary.

[FR Doc. 2011–26845 Filed 10–17–11; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

National Nuclear Security Administration

Amended Record of Decision for the Nuclear Facility Portion of the Chemistry and Metallurgy Research Building Replacement Project at Los Alamos National Laboratory, Los Alamos, NM

AGENCY: National Nuclear Security Administration, U.S. Department of Energy.

ACTION: Amended Record of Decision.

SUMMARY: The National Nuclear Security Administration (NNSA) of the U.S. Department of Energy (DOE) is issuing this Amended Record of Decision (AROD) for the Nuclear Facility portion of the Chemistry and Metallurgy Research Building Replacement (CMRR) Project at the Los Alamos National Laboratory (LANL) in Los Alamos, New Mexico. After completing an EIS, NNSA issued a ROD for the CMRR Project on February 3, 2004, deciding to construct a two-building, partially above-ground, CMRR Facility in Technical Area-55 (TA–55) at LANL. This new facility would replace the aging 60-year-old Chemistry and Metallurgy Research (CMR) Building at LANL, and would ensure the ability to continue to perform analytical chemistry and materials characterization operations using plutonium and other actinides in a safe, secure manner in support of NNSA mission activities. As the CMRR Project planning and design process has progressed over the past 8 years, the first building of the two-building CMRR Facility (the Radiological Laboratory/Utility/Office Building, also known as the RLUOB) has been constructed. During this same time period, primarily as a result of efforts to better understand the seismic environment at the selected construction site in TA–55, several design considerations and ancillary support requirements were identified for the CMRR Nuclear Facility (CMRR–NF) that had not been anticipated in 2003. These design considerations and additional ancillary support requirements were not analyzed in the 2003 CMRR EIS. To address this new information, NNSA recently completed a supplemental environmental impact statement, *Final Supplemental Environmental Impact Statement for the Nuclear Facility Portion of the Chemistry and Metallurgy Research Building Replacement Project at Los Alamos National Laboratory, Los Alamos, New Mexico* (the CMRR–NF SEIS). The CMRR–NF SEIS analyzes the potential environmental impacts of proposed construction changes to the CMRR–NF to address site seismic and safety considerations, as well as newly identified ancillary construction support requirements, such as additional equipment storage areas, soil storage areas, additional transportation needs, and worker parking areas under the Modified CMRR–NF Alternative and compares these impacts to those identified for the construction project selected in the 2004 ROD (No Action Alternative) and for continued operation of the existing CMR facility. NNSA has considered this analysis as well as comments submitted by the public on the Draft and Final CMRR–NF SEIS and has decided to select the Modified CMRR–NF Alternative for constructing and operating the CMRR–NF portion of the CMRR Project. NNSA will select the appropriate Excavation Option (Shallow or Deep) for implementing the construction of this building after initiating final design activities, when additional geotechnical and structural design calculations and more detailed engineering analysis will be performed to support completing the facility design.

FOR FURTHER INFORMATION CONTACT: For further information about the CMRR–NF SEIS or this CMRR–NF AROD, or to receive copies of the CMRR–NF SEIS, contact: Mr. George J. Rael, Assistant Manager Environmental Operations, NEPA Compliance Officer, U.S. Department of Energy, National Nuclear Security Administration, Los Alamos Site Office, 3747 West Jemez Road, Los Alamos, NM 87544. Mr. Rael may be contacted by telephone at 505–606–0397, or via e-mail at: *NEPALASO@doeal.gov.* The CMRR–NF SEIS is posted at *http://www.nnsa.energy.gov/nepa* and also at *http://www.energy.gov/nepa/downloads/eis-0350-s1-final-supplemental-environmental-impact-statement.* For information on the DOE NEPA process, contact: Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance (GC–54), U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586–4600, or leave a message at (800) 472–2756. Additional information regarding DOE NEPA activities and access to many DOE NEPA documents are available on the Internet through the DOE NEPA Web site at: *http://www.energy.gov/nepa.*

SUPPLEMENTARY INFORMATION:

Background

LANL is a multidisciplinary, multipurpose research institution in north-central New Mexico, about 60 miles (97 kilometers) north-northeast of Albuquerque, and about 25 miles (40 kilometers) northwest of Santa Fe. Since the early 1950s, analytical chemistry (AC) and materials characterization (MC) work has been performed in the CMR Building at LANL. The CMR Building provides essential support for various national security missions, including nuclear nonproliferation programs; the manufacturing, development, and surveillance of pits (the fissile core of a nuclear warhead); life extension programs; dismantlement efforts; waste management; material recycle and recovery; and research. The CMR Building is almost 60 years old and near the end of its useful life. Many of its utility systems and structural components are aged, outmoded, and deteriorated. In the 1990s, geological studies identified a seismic fault trace located beneath two of the wings of the CMR Building, which raised concerns about the structural integrity of the facility. Over the long term, NNSA cannot continue to operate the mission-critical AC and MC capabilities in the existing CMR Building at an acceptable

level of risk to worker safety and health. NNSA has already taken steps to minimize the risks associated with continued operations at the CMR Building.

To ensure that NNSA can fulfill its national security mission for the next 50 years in a safe, secure, and environmentally sound manner, NNSA proposed in 2002 to construct a CMR replacement facility, and this became the subject of the 2003 *Environmental Impact Statement for the Chemistry and Metallurgy Research Building Replacement Project, Los Alamos National Laboratory, Los Alamos, New Mexico* (DOE/EIS–0350, CMRR EIS) and the subsequent 2004 ROD (69 FR 6967). Since the issuance of the 2004 ROD, new information on the seismic environment at Los Alamos, as well as revisions to safety system requirements, have become available, indicating that changes to the design of the CMRR–NF are appropriate. The need for additional construction support activities and ancillary construction work spaces has also been identified. These changes resulted in NNSA's decision to prepare a supplement to the 2003 CMRR EIS, the CMRR–NF SEIS, pursuant to the regulations of the Council on Environmental Quality (CEQ) for implementing NEPA (40 CFR Parts 1500–1508) and DOE's NEPA Implementing Procedures (10 CFR Part 1021). Decisions in this AROD are based in part on information and analyses contained in the CMRR–NF SEIS, DOE/EIS–0350–S1.

NEPA Process for the CMRR–NF SEIS

NNSA started the process for preparing the CMRR–NF SEIS by publishing in the **Federal Register** a Notice of Intent to prepare the CMRR–NF SEIS, inviting the public to participate in a scoping process to help shape NNSA's supplemental analysis (75 FR 60745, October 1, 2010). The public scoping period extended from October 1 through November 16, 2010. In preparing the Draft CMRR–NF SEIS, NNSA considered all scoping comments received during the scoping period. The Environmental Protection Agency (EPA) and NNSA simultaneously published Notices of Availability for the Draft CMRR–NF SEIS in the **Federal Register** on April 29, 2011 (76 FR 24021 and 76 FR 24018, respectively). These notices invited public comment on the Draft CMRR–NF SEIS from April 29 through June 13, 2011. NNSA later published another notice in the **Federal Register** on May 16, 2011, extending the public comment period through June 28, 2011 (76 FR 28222), for a total comment period of 60 days. Four public hearings on the Draft CMRR–NF SEIS were held in Los Alamos, Española, Santa Fe, and Albuquerque, New Mexico, from May 23 through May 26, 2011. NNSA issued the Final CMRR–NF SEIS on August 26, 2011, and the EPA published a Notice of Availability for the Final CMRR–NF SEIS on September 2, 2011 (76 FR 54768).

Alternatives Considered

In the CMRR–NF SEIS, NNSA analyzed the potential environmental impacts associated with three alternatives for the CMRR–NF: (1) The No Action Alternative, (2) the Modified CMRR–NF Alternative, and (3) the Continued Use of CMR Building Alternative.

The No Action Alternative (2004 CMRR–NF) analyzed in the CMRR–NF SEIS consists of continuing to implement earlier NNSA decisions issued in the 2004 ROD based on the 2003 CMRR EIS and modified by subsequent NEPA decisions related to site infrastructure. NNSA determined that the building, as conceived in 2003, would not sufficiently meet subsequent safety and seismic requirements to allow the full suite of NNSA mission-assigned work to be conducted.

Two action alternatives were analyzed in the CMRR–NF SEIS: the Modified CMRR–NF Alternative, and the Continued Use of CMR Building Alternative. The Modified CMRR–NF Alternative consists of constructing and operating a new CMRR–NF at TA–55 adjacent to RLUOB, with certain design and construction modifications and additional support activities that address seismic safety, infrastructure enhancements, nuclear-safety-basis requirements, and sustainable design principles. Two construction options were considered under this alternative: the Deep Excavation Option and the Shallow Excavation Option. All necessary AC and MC activities could be performed within the modified CMRR–NF to support the full suite of NNSA mission work. The Continued Use of CMR Building Alternative would consist of continuing to perform a restricted suite of operations in the existing CMR Building with normal maintenance and component replacements at the level needed to sustain programmatic operations for as long as feasible. Administrative and radiological laboratory operations would be conducted in RLUOB at TA–55, and no construction activities would be associated with this alternative.

Preferred Alternative

As discussed in Volume I, Chapter 2, Section 2.9 of the CMRR–NF SEIS, NNSA identified the Modified CMRR–NF Alternative as its preferred alternative in both the Draft and the Final versions of the document. However, NNSA did not identify a preferred construction option in the CMRR–NF SEIS.

Environmentally Preferable Alternative

Considering the long-term need to maintain its capability to conduct AC and MC operations at LANL, NNSA believes that the Modified CMRR–NF Alternative is the environmentally preferable alternative for meeting its full suite of mission work requirements. Replacing the aging CMR Building with a new facility that incorporates modern safety, security, and efficiency standards would improve NNSA's ability to protect human health and the environment both during normal operations and in the event of an accident or natural phenomena event, such as a wildfire or earthquake.

Environmental Impacts of Alternatives

NNSA analyzed the potential impacts of each alternative on: Land use and visual resources; site infrastructure; air quality (including greenhouse gases); noise; geology and soils; surface and groundwater quality; ecological resources; cultural and paleontological resources; socioeconomics; environmental justice; human health; waste management and pollution prevention; transportation; traffic; and cumulative impacts. NNSA also evaluated the potential impacts of each alternative associated with the irreversible or irretrievable commitments of resources, and the relationship between short-term uses of the environment and the maintenance and enhancement of long-term productivity. In addition, NNSA evaluated impacts of potential accidents, including those tied to seismic risk, on workers and surrounding populations. These analyses and results are described in Volume I, Chapter 4 of the CMRR–NF SEIS. The CMRR–NF SEIS includes a classified appendix that analyzes the potential environmental impacts of intentional destructive acts (credible terrorist scenarios) that might occur at the CMRR–NF.

Comments on the Final Supplemental Environmental Impact Statement

Following publication of the Final CMRR–NF SEIS in August 2011, and prior to issuing this AROD, NNSA received 7 comment documents. The appendix to this AROD contains a summary of these comments and provides NNSA's responses for those

cases where in NNSA's view the comment documents introduce new concerns/issues that were not addressed in the Final SEIS. NNSA has concluded that none of the comments received necessitate further NEPA analysis.

Decisions

NNSA's decisions are based on its mission responsibilities and its need to sustain AC and MC work at LANL in a manner that allows it to fulfill these responsibilities in a safe and environmentally conscientious manner. The CMRR–NF would provide vitally essential technical support capabilities to NNSA's national security missions, which include maintaining the nation's nuclear weapons stockpile and nonproliferation programs. NNSA has decided to select the Modified CMRR–NF Alternative to continue AC and MC operations at LANL as described in Volume I, Chapter 2, Sections 2.3 and 2.4 of the CMRR–NF SEIS. NNSA will also initiate the facility disposition of the existing CMR Building and the CMRR–NF as operations cease in those structures. The benefits of implementing the Modified CMRR–NF Alternative include reliable, long-term, consolidated plutonium research and storage capabilities for the nuclear security enterprise with modern technologies and facilities; improved health and safety for workers and the public; improved operational efficiency; and reductions in the long-term cost of operating and maintaining the facility.

Additional Background and Summary of the NEPA Comparison of Excavation Options

When the probabilistic seismic hazards analysis was prepared in 2007 (LA–UR–07–3965), the CMRR Project team proposed and investigated changing the design for the CMRR–NF that had been selected in the 2004 ROD to increase the thickness in certain floors, the height between floors to provide access, and the thickness of the basemat to improve performance in a seismic event. With these changes, the overall building, measured from the bottom of the basemat to the top of the roof, would have been higher. The design was further revised to maintain the above-ground height of the building by providing a deeper building excavation. This design change resulted in the Deep Excavation Option. The Deep Excavation Option would entail excavating through the layer of poorly welded tuff at the construction site and filling the hole with low-slump concrete to the elevation of the bottom of the basemat, as discussed in Volume I, Chapter 2, Section 2.6.2 of the SEIS. The environmental impacts associated with these activities are discussed in Volume I, Chapter 4, Section 4.3.

Scoping comments for the CMRR–NF SEIS requested that NNSA look for and analyze alternative design/construction options for the CMRR–NF, including those which might reduce cost and environmental impact by avoiding the need for a deep excavation. Consistent with the rationale in this request, NNSA performed a review of the requirements for the design of the CMRR–NF, which identified an opportunity to avoid the activities and costs associated with the additional excavation and concrete fill required for the Deep Excavation Option by raising the bottom of the basemat to near the original design elevation. Following this review, NNSA began analyzing this additional option for inclusion in the Draft SEIS. Under this design/construction option for the CMRR–NF, which came to be known as the Shallow Excavation Option, the overall building height (bottom of basemat to top of roof) would remain the same, but the top of the roof would be higher aboveground than it was in the conceptual and preliminary design. Geotechnical reviews performed for this Shallow Excavation Option concluded that the substrate is sufficiently strong to withstand the weight of the proposed CMRR–NF, such that intolerable amounts of seismically- and non-seismically-induced settlement and lateral shifting of the foundation would not occur. The allowable bearing pressure of the soil is much greater than the pressure caused by the buildings. Both the Deep and the Shallow Excavation options require the same sets of safety controls and the SEIS analysis indicates that they are expected to result in similar offsite environmental consequences. However, the Shallow Excavation Option reduces risk and provides some reductions in construction impacts and cost without affecting other building design requirements. Risk reduction would be realized by a decrease in: excavating, hauling, and storing soil (approximately 9,000 fewer truck trips depending on hauling capacity and 309,000 fewer cubic yards of soil excavated); scope of geotechnical monitoring; extent of slope stabilization; and safety precautions for working in a deep hole. Reductions in construction impacts would include a reduced project footprint for excavated spoils storage (20 fewer acres); fewer truck trips on- and off-site from LANL; fewer materials procured (a savings of 250,000 cubic yards of concrete); and reduced water use (8 million fewer gallons over the course of construction).

NNSA will begin the implementation of its decision to select the Modified CMRR–NF Alternative for constructing and operating the CMRR–NF portion of the CMRR Facility Project by conducting additional detailed design and analysis activities. Continuing forward into final design is expected to result in additional refinement of the information available to NNSA for making its selection of the construction option to be implemented. NNSA will select the appropriate Excavation Option for implementing the construction of this building after initiating final design activities when additional geotechnical and structural design calculations and more-detailed design engineering analysis will be conducted. In making its selection, NNSA will consider the data it obtains from these studies and analysis, the moderate distinctions in environmental impacts between the two excavation options, and other relevant factors such as additional evaluation of security features and more-detailed cost estimates.

Mitigation Measures

All practicable means to avoid or minimize environmental harm have been and will continue to be adopted and employed in the design, construction, and operation of the CMRR–NF. CMRR–NF construction activities will follow standard practices required by federal and state licensing and permitting requirements for minimizing construction impacts on air and surface-water quality, noise, operational and public health and safety, and accident prevention. As described in Volume I, Chapter 5 of the CMRR–NF SEIS, NNSA and LANL operate pursuant to a number of environmental laws and regulations, as well as several other controls, including DOE Orders, policies and contractual requirements. Many of these mandate actions that would mitigate potential adverse environmental impacts related to the construction and subsequent operation of the CMRR–NF. Based on consideration of these mandated mitigation actions, and the analyses of the environmental consequences provided in the CMRR–NF SEIS for this action, no additional mitigation measures would be necessary for many resource areas because the potential environmental impacts are expected to be well below acceptable levels set in promulgated standards.

A summary of all prior mitigation commitments for LANL that are either underway or to be initiated are included in the over-arching LANL SWEIS Mitigation Action Plan (SWEIS MAP).

Prior SWEIS MAP commitments include such actions as continued forest management efforts, trail management efforts, and implementation of a variety of site sampling and monitoring measures, as well as measures to reduce potable water use and implement resource conservation initiatives. A Mitigation Action Plan (MAP) for the CMRR–NF SEIS ROD will be issued by NNSA and made available at *http://www.doeal.gov/laso/NEPADocuments.aspx.* This MAP will include specific requirements for: potable water usage reduction measures; traffic flow improvements; and measures to meet electric power peak capacity demands. Starting in 2012, these new mitigation measures specific to the CMRR–NF project will be incorporated into the overall LANL SWEIS MAP. Reporting will be consolidated into subsequent MAP Annual Reports issued by NNSA and made publicly available at: *http://www.lanl.gov/environment/nepa/sweis.shtml.*

In addition, NNSA will continue its on-going efforts to support the local Pueblos and other tribal entities in matters of human health, and will participate in various intergovernmental efforts to protect indigenous practices and locations of concern. NNSA will continue to conduct government-to-government consultations with the Pueblos and other tribal entities to incorporate these matters into the SWEIS MAP, as deemed appropriate.

Issued at Washington, DC, this 12th day of October, 2011.

Thomas P. D'Agostino,

Administrator, National Nuclear Security Administration.

Appendix to the CMRR–NF Amended ROD

Following publication of the *Final Supplemental Environmental Impact Statement for the Nuclear Facility Portion of the Chemistry and Metallurgy Research Building Replacement Project at Los Alamos National Laboratory, Los Alamos New Mexico,* DOE/EIS–0350–S1 (Final CMRR–NF SEIS) in August 2011, and prior to issuing of this Amended Record of Decision (AROD), the National Nuclear Security Administration (NNSA) received seven comment documents related to the Final CMRR–NF SEIS. Having reviewed and fully considered the comments received in the comment documents, NNSA has determined that these comments do not provide information that affects the analysis in the Final CMRR–NF SEIS.

NNSA has further determined that many of the issues in these comment documents are either similar, or in some cases identical to, comments that were submitted on the Draft CMRR–NF SEIS which were addressed by NNSA in the Final CMRR–NF SEIS comment response document (Volume II of the FSEIS). These include comments related to NNSA's implementation of the NEPA process; the requirements for a supplemental environmental impact statement; the purpose and need for action; the range of alternatives evaluated; radioactive contaminants in the environment; consideration of geologic and seismic risks at LANL in facility design; hazards from earthquakes and wildfires; electrical and water usage; management of radioactive materials; waste management; concerns related to environmental cleanup; decontamination, decommissioning, and demolition of the CMRR–NF; pit production and stockpile stewardship; arms reduction and nonproliferation treaty compliance; and facility costs and potential other uses of funds. NNSA has determined that is appropriate to respond further to the following comments extracted from these seven documents and summarized below:

Comment 1: The CMRR–NF SEIS Comment Response Document (CRD) (Volume 2) did not include all comments received.

Response: NNSA endeavored to include in the CRD all comments that it received in response to the Draft SEIS but inadvertently overlooked one letter which was a variant of Campaign Y. In the CRD, NNSA categorized letters with similar language as ''campaigns'' for the purpose of providing a consolidated response. The omitted letter mirrored the Campaign Y letter, and also included comments on four additional issues: (1) Alternative designation in the SEIS, (2) electricity use at LANL during construction of the CMRR–NF, (3) transuranic waste disposal, and (4) the ability of the preferred site to support the weight of the proposed CMRR–NF. After reviewing these additional comments, NNSA has concluded that they were addressed in NNSA's responses to other comments received during the public comment period (*see, e.g.,* responses to comments 108–3, 153–5, 204–37, and 57–1, respectively). Therefore, NNSA does not believe that this inadvertent oversight affects the analysis in the Final SEIS or this decision document. No other commentors contacted NNSA to communicate that their comments were not included in the CRD.

Comment 2: The Final CMRR–NF SEIS does not state which Construction Option NNSA prefers for the Modified CMRR–N F Alternative (Shallow Excavation Option or Deep Excavation Option).

Response: NNSA prepared the final CMRR–NF SEIS document in accordance with CEQ and DOE NEPA regulations which require the identification of a preferred alternative in a Final EIS document, by identifying the Modified CMRR–NF Alternative as its preferred Alternative. (See Volume I, Chapter 2, Section 2.9.) NNSA analyzed and presented within the CMRR–NF SEIS the full range of potential direct, indirect, and cumulative impacts for each of the two options (Shallow Excavation and Deep Excavation) that NNSA identified for construction of the preferred alternative.

Both the Deep and the Shallow Excavation options contemplate construction of essentially the same building structure to provide the same functional capabilities. Thus both options require the same sets of safety controls and key equipment. Further, as the SEIS analysis indicates, once construction is complete and operations commence, both options are expected to result in similar offsite environmental consequences. The additional geotechnical and structural design calculations and more detailed engineering analysis NNSA will conduct pursuant to the decision announced in this AROD, prior to selecting a construction option for implementation, are not expected to identify any additional environmental impacts associated with either excavation option beyond those analyzed and presented in the final SEIS.

Comment 3: The reference, *Interim Report, Update of the Probabilistic Seismic Hazard Analysis and Development of CMRR Design Ground Motions Los Alamos National Laboratory, New Mexico,* was not included in the April 2011 draft document, and therefore the public did not have an opportunity to review and comment on it.

Response: As discussed in the Final CMRR–NF SEIS, the reference, a 2009 update to the 2007 probabilistic seismic hazard analysis (PSHA), was not publicly available at the time the Draft CMRR–NF SEIS was prepared; however, it has subsequently been made available to the public upon request and has been incorporated into the Final CMRR–NF SEIS. Based on the 2009 study, the TA–55 horizontal and vertical peak ground acceleration values for a 2,500-year return period showed a reduction in acceleration values compared to the 2007 study. However, the more conservative acceleration values from the 2007 study are currently being used

for the seismic design of the CMRR–NF structure, and the public did have an opportunity to review and comment on those values. Regardless of whether the 2007 or 2009 study values are used, NNSA plans to construct the CMRR–NF to meet the requirements of a performance category 3 structure as discussed in the Final CMRR–NF SEIS.

Comment 4: LANL should immediately install a network of weak motion seismographs to improve knowledge of kappa.

Response: LANL has both weak and strong motion seismic networks that continue to be updated and improved. Numerous earthquakes have been recorded by the weak motion network and are part of the earthquake catalog referenced in the probabilistic seismic hazard analysis (PSHA). Inference of a value for kappa requires an earthquake recording that is on-scale and has significant bandwidth as documented in the 2007 PSHA. Because of this requirement, the number of records that can be used for estimating a value for kappa is limited. LANL has and will continue to improve and upgrade the seismic network. As additional seismic data are collected by the LANL weak and strong motion seismic arrays, the value of kappa will be further refined and its uncertainty reduced. However, further refinement of the value of kappa is not essential for the purposes of the environmental impact analysis.

[FR Doc. 2011–26881 Filed 10–17–11; 8:45 am]

BILLING CODE 6450–01–P

FEDERAL COMMUNICATIONS COMMISSION

Federal Advisory Committee Act; Advisory Committee on Diversity for Communications in the Digital Age

AGENCY: Federal Communications Commission.

ACTION: Notice of public meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, this notice advises interested persons that the Federal Communications Commission's (FCC) Advisory Committee on Diversity for Communications in the Digital Age (''Diversity Committee''). The Committee's mission is to provide recommendations to the Commission regarding policies and practices that will further enhance diversity in the telecommunications and related industries. In particular, the Committee will focus primarily on lowering barriers to entry for historically disadvantaged men and women, exploring ways in which to ensure universal access to and adoption of broadband, and creating an environment that enables employment of a diverse workforce within the telecommunications and related industries. The Committee will be charged with gathering the data and information necessary to formulate meaningful recommendations for these objectives.

DATES: Tuesday, December 6, 2011 at 2 p.m.

ADDRESSES: Federal Communications Commission, Room TW–C305 (Commission Meeting Room, TW–C305), 445 12th Street, SW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Barbara Kreisman, 202–418–1605; *Barbara.Kreisman@FCC.gov*.

SUPPLEMENTARY INFORMATION: This is the first meeting of the Diversity Federal Advisory Committee under its current charter. At this meeting the new committee structure and other organizational matters will be discussed. Further, the substantive direction and goals of this committee will also be considered.

Members of the general public may attend the meeting. The FCC will attempt to accommodate as many people as possible. However, admittance will be limited to seating availability. The public may submit written comments before the meeting to: Barbara Kreisman, the FCC's Designated Federal Officer for the Diversity Committee by e-mail: *Barbara.Kreisman@fcc.gov* or U.S. Postal Service Mail (Barbara Kreisman, Federal Communications Commission, Room 2–A665, 445 12th Street, SW., Washington, DC 20554).

Open captioning will be provided for this event. Other reasonable accommodations for people with disabilities are available upon request. Requests for such accommodations should be submitted via e-mail to *fcc504@fcc.gov* or by calling the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (tty). Such requests should include a detailed description of the accommodation needed. In addition, please include a way we can contact you if we need more information. Please allow at least five days advance notice; last minute requests will be accepted, but may be impossible to fill.

Additional information regarding the Diversity Committee can be found at *http://www.fcc.gov/DiversityFAC*.

Federal Communications Commission.

Barbara A. Kreisman,

Chief, Video Division, Media Bureau.

[FR Doc. 2011–26818 Filed 10–17–11; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL TRADE COMMISSION

Granting of Request for Early Termination of the Waiting Period Under the Premerger Notification Rules

Section 7A of the Clayton Act, 15 U.S.C. 18a, as added by Title II of the Hart-Scott-Rodin Antitrust Improvements Act of 1976, requires persons contemplating certain mergers or acquisitions to give the Federal Trade Commission and the Assistant Attorney General advance notice and to wait designated periods before consummation of such plans. Section 7A(b)(2) of the Act permits the agencies, in individual cases, to terminate this waiting period prior to its expiration and requires that notice of this action be published in the **Federal Register**.

The following transactions were granted early termination—on the dates indicated—of the waiting period provided by law and the premerger notification rules. The listing for each transaction includes the transaction number and the parties to the transaction. The grants were made by the Federal Trade Commission and the Assistant Attorney General for the Antitrust Division of the Department of Justice. Neither agency intends to take any action with respect to these proposed acquisitions during the applicable waiting period.

EARLY TERMINATIONS GRANTED SEPTEMBER 1, 2011 THRU SEPTEMBER 30, 2011

09/01/2011		
20111162	G	Health Management Associates, Inc.; Catholic Health Partners; Health Management Associates, Inc.

EARLY TERMINATIONS GRANTED SEPTEMBER 1, 2011 THRU SEPTEMBER 30, 2011—Continued

09/02/2011		
20110573	G	DaVita Inc.; CDSI I Holding Company, Inc.; DaVita Inc.
20110687	G	Dawson Geophysical Company; TGC Industries, Inc.; Dawson Geophysical Company.
20110858	G	Precision Castparts Corp.; Paul L. Briles, Inc.; Precision Castparts Corp.
20111317	G	Hajoca Corporation; HDS Investment Holding, Inc.; Hajoca Corporation.
20111319	G	International Equipment Solutions, LLC; Dover Corporation; International Equipment Solutions, LLC.
20111320	G	Providence Equity Partners VI L.P.; The Fourth Viscount Rothermere; Providence Equity Partners VI L.P.
20111321	G	Compagnie de Saint-Gobain; NV Bekaert SA; Compagnie de Saint-Gobain.
20111323	G	WPP plc; Steven Wayne Clark; WPP plc.
20111326	G	JS Group Corporation; Cima Claddings S.A.; JS Group Corporation.
09/06/2011		
20111328	G	Chico's FAS, Inc.; Boston Proper, Inc.; Chico's FAS, Inc.
09/07/2011		
20111241	G	Acer Incorporated; iGware, Inc.; Acer Incorporated.
20111266	G	Consumer Portfolio Services, Inc.; Unitrin, Inc.; Consumer Portfolio Services, Inc.
09/08/2011		
20111269	G	VWarburg Pincus Private Equity X, L.P.; Adam S. Bold; Warburg Pincus Private Equity X, L.P.
20111296	G	Blackstone Capital Partners VI, L.P.; Emdeon Inc.; Blackstone Capital Partners VI, L.P.
20111313	G	Boyd Gaming Corporation; Engelstad Family Foundation; Boyd Gaming Corporation.
09/09/2011		
20111274	G	Armor TPG Holdings LLC; Armstrong World Industries, Inc. Asbestos Personal Injury; Armor TPG Holdings LLC.
20111287	G	Kieppe Patrimonial Ltda; The Dow Chemical Company; Kieppe Patrimonial Ltda.
09/12/2011		
20111107	G	Fiserv, Inc.; CashEdge Inc.; Fiserv, Inc.
20111302	G	Crestview Partners II, L.P.; Cumulus Media Inc.; Crestview Partners II, L.P.
20111310	G	HTC Corporation; Ms. Cher Wang; HTC Corporation.
20111334	G	Hisdesat Servicios Estrategicos, S.A.; Loral Space & Communications Inc.; Hisdesat Servicios Estrategicos, S.A.
20111340	G	TrueCar, Inc.; DealerTrack Holdings, Inc.; TrueCar, Inc.
20111341	G	DealerTrack Holdings, Inc.; TrueCar, Inc.; DealerTrack Holdings, Inc.
20111343	G	Holly Energy Partners, L.P.; HollyFrontier Corporation; Holly Energy Partners, L.P.
20111344	G	Lockheed Martin Corporation; Spectrum Equity Investors IV, L.P.; Lockheed Martin Corporation.
20111348	G	Alinda Infrastructure Fund II, L.P.; ArcLight Energy Partners Fund IV, LP; Alinda Infrastructure Fund H, L.P.
20111352	G	TA XI L.P.; Aicent, Inc.; TA XI L.P.
20111357	G	NGL Energy Partners LP; Vincent J. Osterman; NGL Energy Partners LP.
20111358	G	NGL Energy Partners LP; Ernest Osterman; NGL Energy Partners LP.
20111360	G	Smiths Group plc; Bertram Growth Capital I, L.P.; Smiths Group plc.
20111361	G	Valero Energy Corporation; Murphy Oil Corporation; Valero Energy Corporation.
20111363	G	Wells Fargo & Company; Cargill, Incorporated; Wells Fargo & Company.
20111364	G	Cumulus Media Inc.; Citadel Broadcasting Corporation; Cumulus Media Inc.
20111367	G	Insight Equity II LP; Merit Mezzanine Fund IV, L.P.; Insight Equity II LP.
09/13/2011		
20111329	G	General Dynamics Corporation; The Veritas Capital Fund III, L.P.; General Dynamics Corporation.
20111332	G	Energy Capital Partners II–A, LP; Strategic Value Restructuring Fund, Ltd.; Energy Capital Partners II–A, LP.
20111350	G	Advent (OT) Cayman Ltd.; Francois-Charles Oberthur SAS; Advent (OT) Cayman Ltd.
20111362	G	Ladenburg Thalmann Financial Services Inc.; Ameriprise Financial, Inc.; Ladenburg Thalmann Financial Services Inc.
09/14/2011		
20111150	G	National Oilwell Varco, Inc.; Ameron International Corporation; National Oilwell Varco, Inc.
09/15/2011		
20111342	G	Glazer's, Inc.; Halo Distributing co.; Glazer's, Inc.
20111355	G	Michael R. Bloomberg; The Bureau of National Affairs, Inc.; Michael R. Bloomberg.
09/16/2011		
20111143	G	S1 Corporation; Nochi Dankner; S1 Corporation.
20111167	S1	Nochi Dankner; G Corporation; Nochi Dankner.
20111339	G	Noble Energy, Inc.; JV, LLC; Noble Energy, Inc.
20111368	G	Time Warner Cable Inc.; Insight Communications Company, Inc.; Time Warner Cable Inc.
20111375	G	International Business Machines Corporation; Silver Lake Sumeru Fund Cayman, L.P.; International Business Machines Corporation.

EARLY TERMINATIONS GRANTED SEPTEMBER 1, 2011 THRU SEPTEMBER 30, 2011—Continued

20111390	G	RPM International Inc.; Skagit Northwest Holdings, Inc.; RPM International Inc.
		09/19/2011
20111346	G	Liquidity Services, Inc.; WGD, Inc.; Liquidity Services, Inc.
20111365	G	Liberty Media Corporation; Barnes & Noble, Inc.; Liberty Media Corporation.
		09/20/2011
20111325	G	SPX Corporation; Clyde Blowers Capital Fund II, LP; SPX Corporation.
20111331	G	Permira IV Continuing L.P. 2; Terrance D. and Judith A. Paul; Permira IV Continuing L.P. 2.
20111372	G	Alere Inc.; John T. Rich, Sr.; Alere Inc.
20111373	G	ARAMARK Holdings Corporation; Green Mountain Coffee Roasters, Inc.; ARAMARK Holdings.
		09/21/2011
20111376	G	William Robertson; FirstEnergy Corp.; William Robertson.
20111380	G	LS Power Equity Partners II, L.P.; NextEra Energy, Inc.; LS Power Equity Partners II, L.P.
20111381	G	Welsh, Carson, Anderson & Stowe XI, L.P.; Community Care Health Network, Inc.; Welsh, Carson, Anderson & Stowe XI, L.P.
20111383	G	Carlyle U.S. Growth Fund III, L.P.; WH Blocker, Inc.; Carlyle U.S. Growth Fund III, L.P.
		09/22/2011
20111327	G	Biglari Holdings, Inc.; Cracker Barrel Old Country Store, Inc.; Biglari Holdings, Inc.
20111366	G	Baker Brothers Life Sciences, L.P.; Pharmacyclics, Inc.; Baker Brothers Life Sciences, L.P.
		09/23/2011
20111385	G	Sinclair Broadcast Group, Inc.; Cerberus Institutional Partners, L.P.; Sinclair Broadcast Group, Inc.
20111387	G	Computershare Limited; Shinsei Bank, Limited; Computershare Limited.
20111391	G	BMG RM Investments Luxembourg S.a.r.l; Spectrum Equity Investors V, L.P.; BMG RM Investments Luxembourg S.a.r.l.
20111395	G	NGL Energy Partners LP; SemGroup Corporation; NGL Energy Partners LP.
20111396	G	Warburg Pincus Private Equity X, L.P.; Arlington Capital Partners II, L.P.; Warburg Pincus Private Equity X, LP.
20111400	G	FREI Bravo AIV, L.P.; First ECA Holdings LLC; FREI Bravo AIV, L.P.
20111404	G	Hyosung Corporation; Global Safety Textiles HoldCo One GmbH; Hyosung Corporation.
		09/26/2011
20111378	G	Trencap s.e.c.; Central Vermont Public Service Corp.; Trencap s.e.c.
20111394	G	Halliburton Company; James B. Archer; Halliburton Company.
20111402	G	Teradyne, Inc.; LitePoint Corporation; Teradyne, Inc.
20111410	G	Summit Midstream Partners, LLC; Encana Corporation; Summit Midstream Partners, LLC.
		09/27/2011
20111333	G	Blackstone Capital Partners V L.P.; Welsh, Carson, Anderson & Stowe X, L.P.; Blackstone Capital Partners V LP.
20111345	G	E. Merck KG; Amnis Corporation; E. Merck KG.
20111379	G	Trencap s.e.c.; Vermont Transco LLC; Trencap s.e.c.
		09/28/2011
20110839	G	Temasek Holdings (Private) Limited; Level 3 Communications, Inc.; Temasek Holdings (Private) Limited.
20110840	G	Level 3 Communications, Inc.; Temasek Holdings (Private) Limited; Level 3 Communications, Inc.
		09/29/2011
20111384	G	GTCR Fund X/B LP; Terrance R. Ahem; GTCR Fund X/B LP.
20111403	G	Philip F. Anschutz; The Oklahoma Publishing Company; Philip F. Anschutz.
		09/30/2011
20111377	G	Atlas Capital Resources (A2–Cayman) LP; International Paper Company; Atlas Capital Resources (A2–Cayman) LP.
20111399	G	Stryker Corporation; Concentric Medical, Inc.; Stryker Corporation.
20111405	G	Global Advanced Metals Pty Ltd; Cabot Corporation; Global Advanced Metals Pty Ltd.
20111411	G	Cameron International Corp.; Joy Global Inc.; Cameron International Corp.
20111416	G	Hellman & Friedman Capital Partners VII, L.P.; Carlyle Partners V. L.P.; Hellman & Friedman Capital Partners VII, LP.
20111417	G	Ronald O. Perelman; M&F Worldwide Corp.; Ronald O. Perelman.
20111418	G	International Business Machines Corporation; Marc Ladreit de Lacharriere; International Business Machines Corporation.
20111426	G	Platinum Equity Capital Partners II, L.P.; Carlyle Strategic Partners, L.P.; Platinum Equity Capital Partners II, L.P.
20111436	G	Littlejohn Fund IV, L.P.; CHS Private Equity V LP; Littlejohn Fund IV, L.P.

FOR FURTHER INFORMATION CONTACT: Renee Chapman, Contact Representative, or Theresa Kingsberry, Legal Assistant, Federal Trade Commission, Premerger Notification Office Bureau of Competition, Room H–303, Washington, DC 20580, (202) 326–3100.

By direction of the Commission.

Donald S. Clark,

Secretary.

[FR Doc. 2011–26796 Filed 10–17–11; 8:45 am]

BILLING CODE 6750–01–M

GENERAL SERVICES ADMINISTRATION

[[OMB Control No. 3090–0250; Docket No. 2011–0016; Sequence 3]

General Services Administration Acquisition Regulation; Submission for OMB Review; Zero Burden Information Collection Reports

AGENCY: Office of the Chief Acquisition Officer, GSA.

ACTION: Notice of request for comments regarding a renewal to an existing OMB clearance.

SUMMARY: Under the provisions of the Paperwork Reduction Act, the Regulatory Secretariat will be submitting to the Office of Management and Budget (OMB) a request to review and approve a reinstatement of a previously approved information collection requirement regarding zero burden information collection reports. A notice was published in the **Federal Register** at 76 FR 38396, on June 30, 2011. No comments were received.

Public comments are particularly invited on: Whether this collection of information is necessary and whether it will have practical utility; whether our estimate of the public burden of this collection of information is accurate and based on valid assumptions and methodology; and ways to enhance the quality, utility, and clarity of the information to be collected.

DATES: Submit comments on or before: November 17, 2011.

FOR FURTHER INFORMATION CONTACT: Ms. Deborah Lague, Procurement Analyst, Contract Policy Division, at telephone (202) 694–8149 or via e-mail to *Deborah.lague@gsa.gov.*

ADDRESSES: Submit comments identified by Information Collection 3090–0250, Zero Burden Information Collection Reports, by any of the following methods:

- Regulations.gov: *http://www.regulations.gov.* Submit comments via the Federal eRulemaking portal by inputting ''Information Collection 3090–0250, Zero Burden Information Collection Reports'', under the heading ''Enter Keyword or ID'' and selecting ''Search''. Select the link ''Submit a Comment'' that corresponds with ''Information Collection 3090–0250, Zero Burden Information Collection Reports''. Follow the instructions provided at the ''Submit a Comment'' screen. Please include your name, company name (if any), and ''Information Collection 3090–0250, Zero Burden Information Collection Reports'' on your attached document.
- *Fax:* (202) 501–4067.
- *Mail:* General Services Administration, Regulatory Secretariat (MVCB), 1275 First Street, NE., Washington, DC 20417. ATTN: Hada Flowers/IC 3090–0250, Zero Burden Information Collection Reports.

Instructions: Please submit comments only and cite Information Collection 3090–0250, Zero Burden Information Collection Reports, in all correspondence related to this collection. All comments received will be posted without change to *http://www.regulations.gov,* including any personal and/or business confidential information provided.

SUPPLEMENTARY INFORMATION:

A. Purpose

This information requirement consists of reports that do not impose collection burdens upon the public. These collections require information which is already available to the public at large or that is routinely exchanged by firms during the normal course of business. A general control number for these collections decreases the amount of paperwork generated by the approval process.

GSA has published rules in the **Federal Register** that fall under information collection 3090–0250. The rule that prescribed clause 552.238–70 ''Identification of Electronic Office Equipment Providing Accessibility for the Handicapped'' was published at 56 FR 29442, June 27, 1991, titled ''Implementation of Public Law 99–506'', with an effective date of July 8, 1991; and Clause 552.238–74 ''Industrial Funding Fee and Sales Reporting'' published at 68 FR 41286, July 11, 2003.

B. Annual Reporting Burden

None.

Obtaining Copies of Proposals: Requesters may obtain a copy of the information collection documents from the General Services Administration, Regulatory Secretariat (MVCB), 1275 First Street, NE., Washington, DC 20407, telephone (202) 501–4755. Please cite OMB Control No. 3090–0250, Zero Burden Information Collection Reports, in all correspondence.

Dated: October 12, 2011.

Laura Auletta,

Acting Director, Office of Governmentwide Acquisition Policy, Office of Acquisition Policy.

[FR Doc. 2011–26895 Filed 10–17–11; 8:45 am]

BILLING CODE 6820–61–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[30-Day–12–11IP]

Agency Forms Undergoing Paperwork Reduction Act Review

The Centers for Disease Control and Prevention (CDC) publishes a list of information collection requests under review by the Office of Management and Budget (OMB) in compliance with the Paperwork Reduction Act (44 U.S.C. Chapter 35). To request a copy of these requests, call the CDC Reports Clearance Officer at (404) 639–5960 or send an e-mail to *omb@cdc.gov.* Send written comments to CDC Desk Officer, Office of Management and Budget, Washington, DC 20503 or by fax to (202) 395–5806. Written comments should be received within 30 days of this notice.

Proposed Project

Workplace Violence Prevention Programs in NJ Healthcare Facilities—New—National Institute for Occupational Safety and Health (NIOSH), Centers for Disease Control and Prevention (CDC).

The long-term goal of the proposed project is to reduce violence against healthcare workers. The objective of the proposed study is two-fold: (1) To examine healthcare facility compliance with the New Jersey Violence Prevention in Health Care Facilities Act, and (2) to evaluate the effectiveness of the regulations in this Act in reducing assault injuries to workers. Our central hypothesis is that facilities with high compliance with the regulations will have lower rates of employee violence-related injury. First, we will conduct face-to-face interviews with the chairs of the Violence Prevention Committees who are in charge of overseeing compliance efforts. The purpose of the interviews is to measure compliance to the state regulations (violence prevention policies, reporting systems

for violent events, violence prevention committee, written violence prevention plan, violence risk assessments, post incident response and violence prevention training). Second, we will also collect assault injury data from facility violent event reports 3 years pre-regulation (2009–2011) and 3 years post-regulation (2012–2014). The purpose of collecting these data is to evaluate changes in assault injury rates before and after enactment of the regulations. Third, we will conduct a nurse survey. The survey will describe the workplace violence prevention training nurses receive following enactment of the New Jersey regulations.

Background and Brief Description

Healthcare workers are nearly five times more likely to be victims of violence than workers in all industries combined [1]. While healthcare workers are not at particularly high risk for job-related homicide, nearly 60% of all nonfatal assaults occurring in private industry are experienced in healthcare. Six states have enacted laws to reduce violence against healthcare workers by requiring workplace violence prevention programs [2]. However, little is understood about how effective these laws are in reducing violence against healthcare workers.

We will test our central hypothesis by accomplishing the following specific aims:

1. Compare the comprehensiveness of healthcare facility workplace violence prevention programs before and after enactment of the New Jersey regulations; *Working hypothesis:* Based on our preliminary research, we hypothesize that enactment of the regulations will improve the comprehensiveness of hospital workplace violence prevention program policies, procedures and training.

2. Describe the workplace violence prevention training nurses receive following enactment of the New Jersey regulations; *Working hypothesis:* Based on our preliminary research, we hypothesize that nurses receive at least 80% of the workplace violence prevention training components mandated in the New Jersey regulations.

3. Examine patterns of assault injuries to workers before and after enactment of the regulations; *Working hypothesis:* Based on our preliminary research, we hypothesize that rates of assault injuries to workers will decrease following enactment of the regulations.

Healthcare facilities falling under the regulations are eligible for study inclusion (i.e., general acute care hospitals and psychiatric facilities). We will conduct face-to-face interviews with the chairs of the Violence Prevention Committees, who as stated in regulations, are in charge of overseeing compliance efforts. These individuals will include hospital administrators, security directors and/or risk managers, many of whom participated in the California study. The purpose of the interviews is to measure compliance to the state regulations (Aim 1). The interview form was pilot-tested by the study team in the Fall 2010 and includes the following components as mandated in the regulations: violence prevention policies, reporting systems for violent events, violence prevention committee, written violence prevention plan, violence risk assessments, post incident response and violence prevention training. Questions will also be asked about barriers and facilitators to developing the violence prevention program. These data will be collected in the post-regulation time period; data collected from New Jersey hospitals in the California study will be used as the baseline measure for evaluating compliance.

We will also collect assault injury data from facility violent event reports 3 years pre-regulation (2009–2011) and 3 years post-regulation (2012–2014). The purpose of collecting these data is to evaluate changes in assault injury rates before and after enactment of the regulations (Aim 3). The abstraction form was developed to collect the specific reporting components stated in the regulations: date, time and location of the incident; identity, job title and job task of the victim; identity of the perpetrator; description of the violent act, including whether a weapon was used; description of physical injuries; number of employees in the vicinity when the incident occurred, and their actions in response to the incident; recommendations of police advisors, employees or consultants, and; actions taken by the facility in response to the incident. No employee or perpetrator identifiable information will be collected.

In addition to health care facilities, nurses will also be recruited. These nurses will be recruited from a mailing list of nurses licensed from the State of New Jersey Division of Consumer Affairs Board of Nursing. The mailing list was selected as the population source of workers due to the ability to capture all licensed nurses in New Jersey. A similar listing does not exist for non-licensed frontline workers, such as aides and orderlies. Therefore, a sampling frame based on nurses (registered nurses and licensed practical nurses) will be used to select workers to participate in the study. A random sample of 2000 registered and licensed practical nurses will be recruited for study participation. A third-party contractor will be responsible for sending the survey to the random sample of 2000. The Health Professionals and Allied Employees union will promote the survey to their members. To maintain the worker's anonymity, the facility in which he/she works will not be identified. The survey will describe the workplace violence prevention training nurses receive following enactment of the New Jersey regulations (Aim 2).

There are no costs to the respondents other than their time. The total estimated annual burden hours are 817.

ESTIMATED ANNUALIZED BURDEN HOURS

Type of respondent	Form name	No. of respondents	Responses per respondent	Average burden per response (in hrs)
Hospital Administrators	Evaluation of Hospital Workplace Violence Prevention Program.	50	1	1
Hospital Administrators	Committee Chair Interview	50	1	1
Hospital Administrators	Employee Incident Information	50	1	1
Nurses (RN and LPN)	Healthcare Facility Workplace Violence Prevention Programs Nurse Survey.	2000	1	20/60

Dated: October 12, 2011.

Daniel Holcomb,

Reports Clearance Officer, Centers for Disease Control and Prevention.

[FR Doc. 2011–26929 Filed 10–17–11; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[Docket Number NIOSH–245]

Request for Public Comment on Draft Document: ''Criteria for a Recommended Standard: Occupational Exposure to Diacetyl and 2,3-pentanedione''; Extension of Comment Period

AGENCY: National Institute for Occupational Safety and Health (NIOSH) of the Centers for Disease Control and Prevention (CDC), Department of Health and Human Services (HHS).

ACTION: Notice and extension of public comment period.

SUMMARY: The National Institute for Occupational Safety and Health (NIOSH) of the Centers for Disease Control and Prevention (CDC) is extending to November 18, 2011, the comment period for the notice that appeared in the **Federal Register** of July 25, 2011 (76 FR 44338–44339). In the Notice, NIOSH announced its intent to hold a public meeting to discuss and obtain comments on the draft document, ''Criteria for a Recommended Standard: Occupational Exposure to Diacetyl and 2,3-pentanedione'' with a comment period ending on October 14, 2011. A copy of the draft document was posted on the Internet at: *http://www.cdc.gov/niosh/docket/review/docket245/* for Docket number NIOSH–245. The agency is extending the comment period in response to requests for extensions to permit the public more time to gather and submit information.

Table of Contents

- Dates
- Addresses
- For Further Information Contact

DATES: Written comments on the document will be accepted until November 18, 2011.

ADDRESSES: All material submitted to NIOSH should reference Docket Number NIOSH–245. All electronic comments should be formatted as Microsoft Word or PDF files and make reference to Docket Number NIOSH–245. To submit comments, please use one of these options:

- Send NIOSH comments using the online form at *http://www.cdc.gov/niosh/docket/review/docket245/comments.html.*
- Email: *nioshdocket@cdc.gov.*
- Facsimile: (513) 533–8285.
- Mail: NIOSH Docket Office, Robert A. Taft Laboratories, MS–C34, 4676 Columbia Parkway, Cincinnati, OH 45226.

All information received in response to this notice will be available for public examination and copying at the NIOSH Docket Office, 4676 Columbia Parkway, Room 111, Cincinnati, Ohio 45226. A complete electronic docket containing all comments submitted will be available on the NIOSH docket home page at *http://www.cdc.gov/niosh/docket/archive/docket245.html* and comments will be available in writing by request. NIOSH includes all comments received without change in the docket, including any personal information provided.

FOR FURTHER INFORMATION CONTACT: Lauralynn Taylor McKernan, ScD, CIH, NIOSH, 4676 Columbia Parkway, MS–C32, Cincinnati, OH 45226, telephone (513) 533–8542, fax (513) 533–8230, Email *LMcKernan@cdc.gov.*

Dated: October 12, 2011.

John Howard,

Director, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention.

[FR Doc. 2011–26870 Filed 10–17–11; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[Docket Number NIOSH–247]

Buy Quiet Workshop

AGENCY: National Institute for Occupational Safety and Health (NIOSH) of the Centers for Disease Control and Prevention (CDC), Department of Health and Human Services (HHS).

ACTION: Notice of public meeting.

SUMMARY: The National Institute for Occupational Safety and Health (NIOSH) of the Centers for Disease Control and Prevention (CDC) will be holding a two-day Buy Quiet Workshop. The Workshop is a National Occupational Research Agenda (NORA) activity jointly organized by the NORA Construction Sector and Manufacturing Sector Programs, and the NIOSH Hearing Loss Prevention Cross-sector Program. The purpose of the Workshop is to determine feasibility and functionality of Buy Quiet programs and to explore proactive steps to ensure successful implementation. The Workshop goal is to stimulate the wider adoption of current and future engineering noise controls on machinery and equipment and to motivate the development and implementation of Buy Quiet programs for the Construction and Manufacturing industries.

Date and Time: November 9–10, 2011, 8 a.m.–5 p.m., Eastern Standard Time.

Place: Robert A. Taft Laboratories, Taft Auditorium, 4676 Columbia Parkway, Cincinnati, Ohio 45226.

ADDRESSES: If interested in attending the meeting, please contact the NIOSH Docket Office at:

- *Mail:* NIOSH Docket Office, Robert A. Taft Laboratories, MS–C34, 4676 Columbia Parkway, Cincinnati, Ohio 45226.
- *Facsimile:* (513) 533–8285.
- *E-mail: nioshdocket@cdc.gov*.
- *Telephone:* (513) 533–8611.

Free registration and information on the workshop can be found at *http://www.team-psa.com/BUYQUIET*.

Security Considerations: Due to mandatory security clearance procedures at the Robert A. Taft Laboratories, in-person attendees must present valid government-issued picture identification to security personnel upon entering the parking lot.

Non-U.S. Citizens: Because of CDC Security Regulations, any non-U.S. citizen wishing to attend this meeting must provide the following information in writing to the NIOSH Docket Officer at the address below no later than October 21, 2011:

1. Name:
2. Gender:
3. Date of Birth:
4. Place of birth (city, province, state, country):
5. Citizenship:
6. Passport Number:
7. Date of Passport Issue:
8. Date of Passport Expiration:
9. Type of Visa:
10. U.S. Naturalization Number (if a naturalized citizen):
11. U.S. Naturalization Date (if a naturalized citizen):
12. Visitor's Organization:
13. Organization Address:
14. Organization Telephone Number:
15. Visitor's Position/Title within the Organization:

This information will be transmitted to the CDC Security Office for approval.

Visitors will be notified as soon as approval has been obtained.

Status: The meeting is open to the public, limited only by the space available. The meeting space accommodates approximately 100 people.

SUPPLEMENTARY INFORMATION:

Recommended Attendees: Purchasing agents and buyers of construction and manufacturing machinery and equipment who believe ''Buy Quiet'' programs can be effectively and efficiently woven into existing procurement processes.

Construction and manufacturing employers who wish to investigate the cost effectiveness of ''Buy Quiet'' and determine how best to use the program to demonstrate best available engineering noise control technology is being deployed at their worksites.

Noise control engineers, product designers and manufacturers wishing to learn how best to gather and present noise level information and to provide necessary information to their customers in support of ''Buy Quiet'' programs.

Other safety and health professionals and employee representatives who want to assist in bringing ''Buy Quiet'' programs into the workplace.

Format: Day one will provide presentations from invited speakers. Day two will combine presentations with break-out sessions and roundtable discussions. The break-outs and roundtable will provide participants the opportunity to share relevant experiences and aspirations on process techniques for implementation, incentives and barriers for implementation, and research to practice products and partnerships.

Note: This workshop is not a sales event nor will exhibits of any kind be allowed. Any attendees who attempt to use this meeting for sales purposes will be asked to leave. This meeting is to explore methods for the development and implementation of ''Buy Quiet'' programs that meet the needs of the business community identified as part of the Construction and Manufacturing industry sectors.

Contact Person For More Information: Charles Hayden, NIOSH, MS–C27, Robert A. Taft Laboratories, 4676 Columbia Parkway, Cincinnati, Ohio 45226, telephone (513) 533–8152, E-mail *chayden@cdc.gov.*

Dated: October 12, 2011.

John Howard,

Director, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention.

[FR Doc. 2011–26867 Filed 10–17–11; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0529]

Burden of Food and Drug Administration Food Safety Modernization Act Fee Amounts on Small Business; Extension of Comment Period

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice; extension of comment period.

SUMMARY: The Food and Drug Administration (FDA) is extending the comment period to November 30, 2011, for the notice entitled, ''Burden of Food and Drug Administration Food Safety Modernization Act Fee Amounts on Small Business; Request for Comments'' that appeared in the **Federal Register** of August 1, 2011 (76 FR 45818). In that document, FDA announced the establishment of a docket to obtain information that would be used to formulate a proposed set of guidelines in consideration of the burden of fee amounts on small business, as set forth in the FDA Food Safety Modernization Act (FSMA). In particular, the Agency requested public comments on whether a reduction of fees or other consideration for small business was appropriate, and if so, what factors the Agency should consider for each. In addition, the Agency requested public comment on how small business should be defined or recognized. The Agency is taking this action in response to requests for an extension to allow interested persons additional time to submit comments.

DATES: Submit either electronic or written or comments by November 30, 2011.

ADDRESSES: Submit electronic comments to *http://www.regulations.gov.* Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Alexis Nazario-Negron, Office of Financial Management, Food and Drug Administration, 1350 Piccard Dr., Rm. 210E, Rockville, MD 20850, 301–796–7223, *Alexis.Nazario-Negron@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of August 1, 2011 (76 FR 45818), FDA published a notice with a 78-day comment period to request comments on the burden of FSMA fee amounts on small business. FSMA provides the Agency with authority under section 743 of the Federal Food, Drug, and Cosmetic Act (FD&C Act) to assess and collect fees, including those for costs associated with certain domestic and foreign facility reinspections, failure to comply with a recall order, and importer reinspections. The Agency is seeking public comment on what burdens these fees might impose on small business, and whether and how the Agency should alleviate such burdens. In particular, the Agency is seeking public comments on whether a reduction of fees or other consideration for small business is appropriate, and if so, what factors the Agency should consider for each. In addition, the Agency is seeking public comment on how small business should be defined or recognized. The Agency has received a request for an extension of the comment period. The request conveyed concern that the current 78-day comment period does not allow sufficient time to develop a meaningful or thoughtful response to the notice.

FDA has considered the request and is extending the comment period for the notice until November 30, 2011. The Agency believes that this extension allows adequate time for interested persons to submit comments without significantly delaying the development of a proposed set of guidelines in consideration of the burden of the fee amounts on small business, as required by section 743(b)(2)(B)(iii) of the FD&C Act.

II. Request for Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) either electronic or written comments on this document. It is only necessary to send one set of comments. It is no longer necessary to send two copies of mailed comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

Dated: October 12, 2011.

David Dorsey,

Acting Associate Commissioner for Policy and Planning.

[FR Doc. 2011–26815 Filed 10–17–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2011–N–0002]

Science Advisory Board to the National Center for Toxicological Research; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). At least one portion of the meeting will be closed to the public.

Name of Committee: Science Advisory Board (SAB) to the National Center for Toxicological Research (NCTR).

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on November 8, 2011, from 8:15 a.m. to 5:30 p.m. and on November 9, 2011, from 8:30 a.m. to 1 p.m.

Location: NCTR SAB Conference Room B–12, 3900 NCTR Rd., Jefferson, AR 72079.

Contact Person: Margaret Miller, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 32, rm. 2208, Silver Spring, MD. 20993–0002, 301–796–8890, or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area), and follow the prompts to the desired center or product area. Please call the Information Line for up-to-date information on this meeting. A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site and call the appropriate advisory committee hot line/phone line to learn about possible modifications before coming to the meeting.

Agenda: On November 8, 2011, the NCTR Director will welcome the participants and provide a Center-wide update on scientific initiatives and accomplishments during the past year. The SAB will then briefly review the subcommittee report on the Division of Neurotoxicology, which was adopted by the full committee at the last meeting. The Director of the Division of Neurotoxicology will provide a response to the report, noting the changes that have been implemented based on the recommendations in the report.

A representative from FDA's Office of Science will present the Agency's Regulatory Science Strategic Plan and speak about the Agency's Medical Countermeasure Initiative.

The Directors for the Division of Microbiology and the Division of Personalized Nutrition and Medicine will update the SAB on the major research accomplishments of the past year, the important implications of their findings for FDA, and the research direction of the division, including issues requiring input from the Committee. The SAB will then discuss the research direction and provide advice on the state of the science, future research directions, and impact of the findings on the public health.

The Center representatives from the Center for Veterinary Medicine and the Center for Food Safety and Applied Nutrition will describe their Center's regulatory mandate, public health mission, and strategic research needs, and discuss opportunities for collaboration to help address these needs. This information will be considered by NCTR's SAB in their recommendations for the future direction of NCTR's research activities. Next, a member of the SAB will present future research needs in the area of regulatory science for personalized nutrition.

Following the public session, the SAB will hear a presentation by the representative from the National Toxicology Program (NTP) on the current and future research collaborations between the National Institute of Environmental Health Sciences (NIEHS) and the NCTR. This presentation will be followed by an update from NCTR's Office of Science Coordination on the NTP studies being conducted at NCTR and those studies that will commence during the next year.

Next, the Chair of the Nanotechnology Core Facility Subcommittee will present an overview of the Nanotechnology Core Facility and subcommittee report. On August 16–17, 2011, the subcommittee convened to conduct an indepth review of the NCTR/ORA Nanotechnology Core Facility. The Nanotechnology Core Facility is jointly sponsored by FDA's NCTR and Office of Regulatory Affairs, and NIEHS/NTP to support nanotechnology-related scientific studies through the characterization and detection of nanomaterials in toxicology studies and to develop analytical methods to accurately monitor nanotechnology-based FDA-regulated products. Representatives from FDA's Office of the Commissioner and product Centers, as well as a representative from the NTP/NIEHS, participated in the evaluation. The site visit report will be presented to the full Committee and then open for discussion by all participants before a vote for adoption by the full SAB. All members of the NCTR SAB and the Center representatives will have an opportunity to comment on the Nanotechnology Core Facility Subcommittee report.

Following consideration of the Nanotechnology Core Facility Subcommittee Review report, a member of the SAB will present a vision for research needs to advance regulatory science in the area of pharmaceuticals.

On November 9, 2011, the Center representatives from the Center for Biologics Evaluation and Research and the Center for Drug Evaluation and Research will describe their Center's regulatory mandate, public health mission, and strategic research needs; and discuss opportunities for collaboration to help address these needs. Again, this information will be considered by NCTR's SAB in their recommendations for the future direction of NCTR's research activities.

The Directors for the Division of Biochemical Toxicology and the Division of Systems Biology will update the SAB on the major research accomplishments of the past year, the important implications of the findings for FDA, and the research direction of the division, including issues needing input from the Committee. The SAB will then discuss the research direction and provide advice on the state of the science, future research directions, and impact of the findings on the public health.

NCTR's Center Director will discuss research priorities, alignment of NCTR with the Agency's regulatory science initiative, and the strategic focus for future research at NCTR.

The Center representative from the Center for Devices and Radiological Health and the Center for Tobacco Products will present their regulatory mandate, public health mission, and strategic research needs; and discuss opportunities for collaboration to help address these needs. Again, this information will be considered by NCTR's SAB in their recommendations for the future direction of NCTR's research activities.

The Director for the Division of Genetic and Molecular Toxicology will update the SAB on the major research accomplishments of the past year, the important implications of the findings for FDA, and the research direction of the division, including issues needing

input from the Committee. The SAB will then discuss the research direction and provide advice on the state of the science, future research directions, and impact of the findings on the public health.

Following an open discussion of all the information presented, the open session of the meeting will close so that the SAB members can discuss personnel issues at NCTR.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee link.

Procedure: On November 8, 2011, from 8:15 a.m. to 4:20 p.m., the meeting is open to the public. Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before October 28, 2011. Oral presentations from the public will be scheduled between approximately 1 p.m. to 2 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before October 20, 2011. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by October 21, 2011.

Closed Committee Deliberations: On November 9, 2011, the meeting will be closed to permit discussion where disclosure would constitute a clearly unwarranted invasion of personal privacy (5 U.S.C. 552b(c)(6)). This portion of the meeting will be closed to permit discussion of information concerning individuals associated with the research programs at NCTR.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Margaret Miller at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: October 11, 2011.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2011–26891 Filed 10–17–11; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Agency Information Collection Activities: Proposed Collection; Comment Request; Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

AGENCY: National Institutes of Health, National Institute on Drug Abuse (NIDA), HHS.

ACTION: 30–Day notice of submission of information collection approval from the Office of Management and Budget and request for comments.

SUMMARY: As part of a Federal Government-wide effort to streamline the process to seek feedback from the public on service delivery, NIDA has submitted a Generic Information Collection Request (Generic ICR): ''Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery'' to OMB for approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et. seq.*).

DATES: Comments must be submitted within 30 days after publication in FR.

ADDRESSES: Written comments may be submitted to the Office of Management and Budget, Office of Information and Regulatory Affairs, *Attn:* NIH Desk Officer, by E-mail to *OIRA_submission@omb.eop.gov,* or by fax to 202–395–6974.

FOR FURTHER INFORMATION CONTACT: To request additional information, please contact Genevieve deAlmeida-Morris, Health Research Evaluator, Office of Science Policy and Communications, National Institute on Drug Abuse, 6001 Executive Boulevard, Bethesda, MD 20892–9557, or call non-toll-free number (301) 594–6802 or E-mail your request, including your address to *dealmeig@nida.nih.gov.*

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

Abstract: The information collection activity will garner qualitative customer and stakeholder feedback in an efficient, timely manner, in accordance with the Administration's commitment to improving service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences and expectations, provide an early warning of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative and actionable communications between the Agency and its customers and stakeholders. It will also allow feedback to contribute directly to the improvement of program management.

Feedback collected under this generic clearance will provide useful information, but it will not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address: the target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be

eligible for submission for other generic mechanisms that are designed to yield quantitative results.

No comments were received in response to the 60-day notice published in the **Federal Register** of December 22, 2010 (75 FR 80542).

Below we provide NIDA's projected average estimates for the next three years: [1]

Current Actions: New collection of information.

Type of Review: New Collection.

Affected Public: Individuals and Households, Businesses and Organizations, State, Local or Tribal Government.

Average Expected Annual Number of activities: 4.

Respondents: 740.

Annual responses: 740.

Frequency of Response: Once per request.

Average minutes per response: 50.

Burden hours: 516.

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 Office of Management and Budget control number.

Dated: October 6, 2011.

Mary Affeldt,

Executive Officer (OM Director), NIDA.

[FR Doc. 2011–26906 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Submission for OMB Review; Comment Request; The Hispanic Community Health Study (HCHS)/ Study of Latinos (SOL)

Summary: Under the provisions of Section 3507(a)(1)(D) of the Paperwork Reduction Act of 1995, the National Heart, Lung, and Blood Institute (NHLBI), the National Institutes of Health (NIH) has submitted to the Office of Management and Budget (OMB) a request for review and approval the information collection listed below. This proposed information collection was previously published in the **Federal Register** on August 9, 2011, pages 48872–48873, and allowed 60 days for public comment. Two public comments were received. One comment questioned why government resources are being devoted to studying the health of Hispanic groups. The comment was acknowledged by NHLBI. The second comment, from an advocacy group, inquired about exploring the availability of paid sick leave and its relationship to Hispanic health. NHLBI acknowledged and followed-up on this comment.

The purpose of this notice is to allow an additional 30 days for public comment. The National Institutes of Health may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

Proposed Collection: Title: Hispanic Community Health Study (HCHS)/Study of Latinos (SOL). *Type of Information Collection Request:* Revision of currently approved collection (OMB# 0925–0584). *Need and Use of Information Collection:* The Hispanic Community Health Study (HCHS)/Study of Latinos (SOL) will identify risk factors for cardiovascular and lung disease in Hispanic populations and determine the role of acculturation in the prevalence and development of these diseases. Hispanics, now the largest minority population in the U.S., are influenced by factors associated with immigration from different cultural settings and environments, including changes in diet, activity, community support, working conditions, and health care access. This project is a multicenter, six-and-a-half-year epidemiologic study and will recruit 16,000 Hispanic men and women aged 18–74 in four community-based cohorts in Chicago, Miami, San Diego, and the Bronx. The study will examine measures of obesity, physical activity, nutritional habits, diabetes, lung and sleep function, cognitive function, hearing, and dental conditions. Closely integrated with the research component will be a community and professional education component, with the goals of bringing the research results back to the community, improving recognition and control of risk factors, and attracting and training Hispanic researchers in epidemiology and population-based research. *Frequency of Response:* The participants will be contacted annually. *Affected Public:* Individuals or households; Businesses or other for profit; Small businesses or organizations. *Type of Respondents:* Individuals or households; physicians. The annual reporting burden is as follows: Estimated Number of Respondents: 17,284; *Estimated Number of Responses per Respondent:* 1; Average Burden Hours Per Response: 0.3072; and *Estimated Total Annual Burden Hours Requested:* 5,309. The annualized cost to respondents is estimated at $104,718, assuming respondents time at the rate of $15 per hour and physician time at the rate of $55 per hour. There are no Capital Costs to report. There are no Operating or Maintenance Costs to report.

ESTIMATE OF RESPONDENT BURDEN

[HCHS/SOL]

Type of respondents	Number of respondents	Frequency of response	Average time per response	Annual hour burden
Participant Telephone Interviews				
a. Follow-Up Call, Year 1	1,333	1	0.75	1,000
b. Follow-Up Call, Year 2	5,333	1	0.25	1,333
c. Follow-Up Call, Years 3, 4, 5, 6	9,334	1	0.25	2,334
Subtotal				4,667

[1] The 60-day notice included the following estimate of the aggregate burden hours for this generic clearance federal-wide:

Average Expected Annual Number of activities: 25,000.

Average number of Respondents per Activity: 200.

Annual responses: 5,000,000.

Frequency of Response: Once per request.

Average minutes per response: 12.

Burden hours: 2,500,000.

Non-participant components[1]				
a. Physician, hospital and nursing home contacts for outcomes ascertainment (total = 1,254).	Deaths: 60 CHF: 90 Stroke: 132 CHD: 650 COPD: 210 Asthma: 112	1	0.50	627
b. Informant contact	30	1	0.50	15
Subtotal				642
Grand total				5,309

Request for Comments: Written comments and/or suggestions from the public and affected agencies should address one or more of the following points: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the function of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Direct Comments to OMB: Written comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time, should be directed to the: Office of Management and Budget, Office of Regulatory Affairs, *OIRA_submission@omb.eop.gov* or by fax to 202–395–6974, Attention: Desk Officer for NIH, Attention: Desk Officer for NIH. To request more information on the proposed project or to obtain a copy of the data collection plans and instruments, contact: Dr. Larissa Aviles-Santa, Project Officer, NIH, NHLBI, 6701 Rockledge Drive, MSC 7936, Bethesda, MD 20892–7936, or call non-toll-free number 301–435–1284 or E-mail your request, including your address to: *AvilessantaL@NHLBI.NIH.GOV.*

Comments Due Date: Comments regarding this information collection are best assured of having their full effect if received within 30 days of the date of this publication.

Dated: October 6, 2011.

Michael S. Lauer,

Director, Division of Cardiovascular Sciences, NHLBI, National Institutes of Health.

Dated: October 6, 2011.

Lynn Susulske,

NHLBI Project Clearance Liaison, National Institutes of Health.

[FR Doc. 2011–26949 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.) notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Allergy and Infectious Diseases Special Emphasis Panel, Beyond HAART: Innovative Therapies to Control HIV–1.

Date: November 14–16, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Residence Inn—Bethesda Downtown Hotel, 7335 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Roberta Binder, PhD, Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, NIAID/NIH/DHHS, 6700B Rockledge Drive, Room 3130, Bethesda, MD 20892–7616, 301–496–7966, *rbinder@niaid.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26908 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Diabetes and Digestive and Kidney Diseases; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Diabetes and Digestive and Kidney Diseases Special Emphasis Panel, PAR09–247: Ancillary Studies in Liver Disease and Digestive Disease.

Date: November 10, 2011.

Time: 1:30 p.m. to 3 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Two Democracy Plaza, 6707 Democracy Boulevard, Bethesda, MD 20892, (Telephone Conference Call).

Contact Person: Ann A. Jerkins, PhD, Scientific Review Officer, Review Branch, DEA, NIDDK, National Institutes of Health, Room 759, 6707 Democracy Boulevard, Bethesda, MD 20892–5452, 301–594–2242, *jerkinsa@niddk.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.847, Diabetes,

Endocrinology and Metabolic Research; 93.848, Digestive Diseases and Nutrition Research; 93.849, Kidney Diseases, Urology and Hematology Research, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26907 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel, Disorders in Brain, Neurotransmission and Aging Special Emphasis Panel.

Date: November 1, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (Virtual Meeting).

Contact Person: Pat Manos, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5200, MSC 7846, Bethesda, MD 20892, 301–408–9866, *manospa@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel, PAR11–145: International Research in Infectious Diseases including AIDS (IRIDA).

Date: November 9–10, 2011.

Time: 8:30 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: The St. Gregory Hotel, 2003 M Street, NW., Washington, DC 20036.

Contact Person: Soheyla Saadi, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3211, MSC 7808, Bethesda, MD 20892, 301–435–0903, *saadisoh@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel, Member Conflict: Topics in Infectious Diseases.

Date: November 9–10, 2011.

Time: 8:30 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (Virtual Meeting).

Contact Person: Liangbiao Zheng, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3202, MSC 7808, Bethesda, MD 20892, 301–996–5819, *zhengli@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel, Small Business: Cell, Computational and Molecular Biology.

Date: November 9, 2011.

Time: 10 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications. Westin Grand, 2350 M Street, NW., Washington, DC 20037.

Contact Person: Allen Richon, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6184, MSC 7892, Bethesda, MD 20892, 301–435–1024, *allen.richon@nih.hhs.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26914 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Fellowship: Oncological Sciences.

Date: November 9, 2011.

Time: 11 a.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

Contact Person: Alexander Gubin, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4196, MSC 7812, Bethesda, MD 20892, 301–435–2902, *gubina@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Special Topic: Population Sciences and Epidemiology R15 Applications.

Date: November 9, 2011.

Time: 12 p.m. to 3 p.m.

Agena: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Fungai Chanetsa, MPH, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3135, MSC 7770, Bethesda, MD 20892, 301–408–9436, *fungai.chanetsa@nih.hhs.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Review of Neuroscience AREA Grant Applications.

Date: November 10–11, 2011.

Time: 8 a.m. to 3 p.m.

Agenda: To review and evaluate grant applications.

Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Toby Behar, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4136, MSC 7850, Bethesda, MD 20892, (301) 435–4433, *behart@csr.nih.gov*.

Name of Committee: Center for Scientific Review Special Emphasis Panel; NCRR Resource Review of National Resource for Automated Molecular Microscopy.

Date: November 13–15, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: The Scripps Research Institute, La Jolla, 10550 North Torrey Pines Road, La Jolla, CA 92037.

Contact Person: Jonathan Arias, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5170, MSC 7840, Bethesda, MD 20892, 301–435–2406, *ariasj@csr.nih.gov*.

Name of Committee: AIDS and Related Research Integrated Review Group; Behavioral and Social Science Approaches to Preventing HIV/AIDS Study Section.

Date: November 14–15, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Marriott Wardman Park Washington DC Hotel, 2660 Woodley Road, NW., Washington, DC 20008.

Contact Person: Jose H. Guerrier, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of

Health, 6701 Rockledge Drive, Room 5222, MSC 7852, Bethesda, MD 20892, 301–435–1137, *guerriej@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Fellowship: Chemistry, Biochemistry, Biophysics, and Bioengineering.

Date: November 14–15, 2011.

Time: 11 a.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

Contact Person: Ross D. Shonat, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6172, MSC 7892, Bethesda, MD 20892, 301–435–2786, *ross.shonat@nih.hhs.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflicts: Cystic Fibrosis, Cystic Lung Disease.

Date: November 14, 2011.

Time: 2 p.m. to 4 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

Contact Person: Everett E. Sinnett, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2178, MSC 7818, Bethesda, MD 20892, 301–435–1016, *sinnett@nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR09–129: MLPCN High Throughput Screening Assays for Drug Discovery.

Date: November 15, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Hotel Nikko San Francisco, 222 Mason Street, San Francisco, CA 94102.

Contact Person: Ping Fan, MD, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5154, MSC 7840, Bethesda, MD 20892, 301–408–9971, *fanp@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Small Business: Nephrology.

Date: November 15–16, 2011.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications,

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Atul Sahai, PhD, Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 2188, MSC 7818, Bethesda, MD 20892, 301–435–1198, *sahaia@csr.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26941 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable materials, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders B.

Date: October 20, 2011.

Time: 8 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Lorien Spa and Hotel, 1600 King Street, Alexandria, VA 22314.

Contact Person: Ernest W. Lyons, PhD, Scientific Review Officer, DHHS/NIH/NINDS/DER/SRB, 6001 Executive Boulevard, MSC 9529, Neuroscience Center, Room 3208, Bethesda, MD 20892, 301–496–4056.

This notice is being published less than 15 days prior to the meeting due to the timing limitations imposed by the review and funding cycle.

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders K.

Date: November 4, 2011.

Time: 8 a.m. to 6 p.m.

Agenda: To review and evaluate grant applications.

Place: Melrose Hotel, 2430 Pennsylvania Ave., NW., Washington, DC 20037.

Contact Person: Shanta Rajaram, PhD, Scientific Review Officer, DHHS/NIH/NINDS/DER/SRB, 6001 Executive Boulevard, MSC 9529, Neuroscience Center, Room 3208, Bethesda, MD 20892, 301–435–6033, *rajarams@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.853, Clinical Research Related to Neurological Disorders; 93.854, Biological Basis Research in the Neurosciences, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26930 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Heart, Lung, and Blood Institute; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Heart, Lung, and Blood Institute Special Emphasis Panel, Virtual Reality Technologies for Research and Education in Obesity and Diabetes.

Date: November 7, 2011.

Time: 8 a.m. to 10 a.m.

Agenda: To review and evaluate grant applications.

Place: Crystal Gateway Marriott, 1700 Jefferson Davis Highway, Arlington, VA 22202.

Contact Person: David A. Wilson, PhD, Scientific Review Officer, Office of Scientific Review/DERA, National Heart, Lung, and Blood Institute, 6701 Rockledge Drive, Room 7204, Bethesda, MD 20892–7924, 301–435–0299, *wilsonda2@nhlbi.nih.gov.*

Name of Committee: National Heart, Lung, and Blood Institute Special Emphasis Panel, Virtual Reality Technologies for Research and Education in Obesity and Diabetes.

Date: November 7, 2011.

Time: 10 a.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: Crystal Gateway Marriott, 1700 Jefferson Davis Highway, Arlington, VA 22202.

Contact Person: David A. Wilson, PhD, Scientific Review Officer, Office of Scientific Review/DERA, National Heart, Lung, and Blood Institute, 6701 Rockledge Drive, Room 7204, Bethesda, MD 20892–7924, 301–435–0299, *wilsonda2@nhlbi.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.233, National Center for Sleep Disorders Research; 93.837, Heart and

Vascular Diseases Research; 93.838, Lung Diseases Research; 93.839, Blood Diseases and Resources Research, National Institutes of Health, HHS)

Dated: October 12, 2011.

Jennifer S. Spaeth,

Director, Office of Federal Advisory Committee Policy.

[FR Doc. 2011–26928 Filed 10–17–11; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID: FEMA–2011–0029; OMB No. 1660–0095]

Agency Information Collection Activities: Proposed Collection; Comment Request; National Flood Insurance Program Claims Appeals Process

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: The Federal Emergency Management Agency, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on a proposed revision of a currently approved information collection. In accordance with the Paperwork Reduction Act of 1995, this notice seeks comments concerning revision of the National Flood Insurance Claims Appeals Process. The appeal process establishes a formal mechanism to allow policyholders to appeal the decisions of any insurance agent, adjuster, insurance company, or any FEMA employee or contractor, in cases or unsatisfactory decisions on claims, proof of loss, and loss estimates.

Under this process, FEMA sends the NFIP Flood Insurance Claims Handbook to the policyholder (upon completion of signed policy), which explains to them the appeals process. If the policyholder wishes to appeal a claims decision, that policyholder may appeal it to FEMA. FEMA will acknowledge receipt of a policyholder's appeal in writing and advise such policyholder if additional information is required in order to fully consider the appeal. FEMA will review the documentation submitted by the policyholder, conduct any necessary additional investigation, and advise, both the policyholder and the appropriate flood insurance carrier, of its decision regarding the appeal.

DATES: Comments must be submitted on or before December 19, 2011.

ADDRESSES: To avoid duplicate submissions to the docket, please use only one of the following means to submit comments:

(1) *Online.* Submit comments at *http://www.regulations.gov* under Docket ID FEMA–2011–0029. Follow the instructions for submitting comments.

(2) *Mail.* Submit written comments to Docket Manager, Office of Chief Counsel, DHS/FEMA, 500 C Street, SW., Room 835, Washington, DC 20472–3100.

(3) *Facsimile.* Submit comments to (703) 483–2999.

(4) *E-mail.* Submit comments to *FEMA-POLICY@dhs.gov.* Include Docket ID FEMA–2011–0029 in the subject line.

All submissions received must include the agency name and Docket ID. Regardless of the method used for submitting comments or material, all submissions will be posted, without change, to the Federal eRulemaking Portal at *http://www.regulations.gov,* and will include any personal information you provide. Therefore, submitting this information makes it public. You may wish to read the Privacy Act notice that is available via the link in the footer of *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Dennis Kuhns, Division Director, Risk Insurance Division, 202–212–0429 for additional information. You may contact the Records Management Division for copies of the proposed collection of information at facsimile number (202) 646–3347 or e-mail address: *FEMA-Information-Collections-Management@dhs.gov.*

SUPPLEMENTARY INFORMATION: Section 205 of The Bunning-Bereuter-Blumenauer Flood Insurance Reform Act of 2004, Public Law 108–264 Section 205, 42 U.S.C. 4011 note, requires the Federal Emergency Management Agency to establish by regulation an additional process for the appeal of decisions of flood insurance claims issued through the National Flood Insurance Program. FEMA's regulation at 44 CFR 62.20 details the appeals process.

The process requires policyholders to submit a written appeal to the Federal Emergency Management Agency (Mitigation Directorate/Risk Insurance Division), in the form of a signed letter explaining the nature of their claim appeal, names and titles of persons contacted, dates of contact, contact information, and details of the contact relevant to their claim appeal. These requirements are spelled out to policyholders in the aforementioned NFIP Flood Insurance Claims Handbook. The policyholders are also required to state the basis for their appeal and submit supporting documentation including a copy of the insurer's written denial, in whole or in part, of the claim.

Collection of Information

Title: National Flood Insurance Program Claims Appeals Process.

Type of Information Collection: Revision of a currently approved information collection.

OMB Number: 1660–0095.

Form Titles and Numbers: None.

Abstract: The NFIP claims appeals process requires policyholders to submit a written appeal to the Federal Emergency Management Agency (Mitigation Directorate/Risk Insurance Division), in the form of a signed letter explaining the nature of their claim appeal, names and titles of persons contacted, dates of contact, contact information, and details of the contact relevant to their claim appeal. The policyholders are also required to state the basis for their appeal and submit supporting documentation including a copy of the insurer's written denial, in whole or in part, of the claim.

Affected Public: Individuals or households and Business or other-for-profits.

Estimated Total Annual Burden Hours: 2110 hours.

Estimated Cost: The cost to policyholders would be an annual cost of $464.20 for postage.

Comments

Comments may be submitted as indicated in the **ADDRESSES** caption above. Comments are solicited to (a) evaluate whether the proposed data collection is necessary for the proper performance of the agency, including whether the information shall have practical utility; (b) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (c) enhance the quality, utility, and clarity of the information to be collected; and (d) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology,

e.g., permitting electronic submission of responses.

Gary L. Anderson,

Acting Chief Administrative Officer, Mission Support Bureau, Federal Emergency Management Agency, Department of Homeland Security.

[FR Doc. 2011–26942 Filed 10–17–11; 8:45 am]

BILLING CODE 9110–11–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5556–D–01]

Consolidated Delegation of Authority for the Office of Community Planning and Development

AGENCY: Office of the Secretary, HUD.

ACTION: Notice of delegation of authority.

SUMMARY: This notice updates, clarifies, and consolidates delegations of authority from the Secretary to the Assistant Secretary for Community Planning and Development, the General Deputy Assistant Secretary for Community Planning and Development, and the Deputy Assistant Secretary for Grant Programs.

DATES: *Effective Date:* October 4, 2011.

FOR FURTHER INFORMATION CONTACT: David H. Enzel, Director, Office of Technical Assistance and Management, Department of Housing and Urban Development, 451 7th Street, SW., Room 7228, Washington, DC 20410–7000; telephone number 202–402–5557. (This is not a toll-free number.) For those needing assistance, this number may be accessed through TTY by calling the toll-free Federal Relay Service number at 1–800–877–8339.

SUPPLEMENTARY INFORMATION: Today's **Federal Register** notice updates, clarifies, and consolidates into one notice the authority delegated by the Secretary to the Assistant Secretary for Community Planning and Development, the General Deputy Assistant Secretary for Community Planning and Development, and the Deputy Assistant Secretary for Grant Programs. Clarification of program authorities under existing CPD delegations includes the Neighborhood Stabilization Programs, Community Development Block Grant (CDBG) disaster recovery grants, and homeless assistance programs under the McKinney-Vento Homeless Assistance Act. This notice supersedes all previous delegations to the Assistant Secretary for Community Planning and Development and the General Deputy Assistant Secretary for Community Planning and Development, including the delegation published on September 16, 2003 (68 FR 5423). Published elsewhere in today's **Federal Register** are notices of redelegation of authority from the Assistant Secretary for Community Planning and Development to subordinate employees within the Office of Community Planning and Development.

Section A. Authority Delegated

Except as provided in Section B, the Secretary of HUD delegates to the Assistant Secretary for Community Planning and Development, the General Deputy Assistant Secretary for Community Planning and Development, and the Deputy Assistant Secretary for Grant Programs the authority of the Secretary with respect to the programs and matters listed below in this Section A. Only the Assistant Secretary is delegated the authority to issue or waive regulations covered by section 7(q) of the Department of Housing and Urban Development Act (42 U.S.C. 3535(q)).

1. The AIDS Housing Opportunity Act, Title VIII, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12901–12912); 24 CFR part 574;

2. The Base Closure, Base Closure Community Redevelopment and Homeless Assistance Act of 1994, Public Law 103–421, 108 Stat. 4346 (codified as amended at 10 U.S.C. 2687 note); 24 CFR part 586;

3. Capacity Building for Community Development and Affordable Housing Grants, Section 4 of the HUD Demonstration Act of 1993, Public Law 103–120, 107 Stat. 1148 (codified as amended at 42 U.S.C. 9816 note);

4. Comprehensive Housing Affordability Strategies (CHAS), Title I of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12701 *et seq.*); 24 CFR part 91;

5. Economic Development Initiative grants, as provided for in annual HUD appropriations acts (*e.g.,* the Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003));

6. Urban Empowerment Zones (EZ), as authorized under title 26, subtitle A, chapter 1, subchapter U of the Internal Revenue Code (codified as amended at 26 U.S.C. 1391 *et seq.*); 24 CFR parts 597 and 598;

7. The HOME Investment Partnerships Act, Title II of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12721 *et seq.*); 24 CFR part 92;

8. The Loan Guarantee Recovery Fund under Section 4 of the Church Arson Prevention Act of 1996, Public Law 104–155, 110 Stat. 1392 (codified at 18 U.S.C. 241 note); 24 CFR part 573;

9. Neighborhood Initiatives grants specifically designated in annual HUD appropriations acts (*e.g.,* the Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3034 (2009));

10. The Homelessness Prevention and Rapid Re-Housing Program (HPRP), as authorized under the Homelessness Prevention Fund heading of Division A, Title XII of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115;

11. The Housing Trust Fund (HTF), Section 1338 of the Federal Housing Enterprises Financial Safety and Soundness Act of 1992, added by Section 1131 of Public Law 110–289, 122 Stat. 2654 (codified at 12 U.S.C. 4568);

12. Rural Innovation Fund grants as provided for in annual HUD appropriations act(s) (*e.g.,* the Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3084 (2009));

13. The Tax Credit Assistance Program (TCAP), as authorized under the HOME Investments Partnerships Program heading of Division A, Title XII of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 155, 220–21;

14. The Self-Help Housing Opportunity Program (SHOP) under section 11 of the Housing Opportunity Program Extension Act of 1996, Public Law 104–120, 110 Stat. 834 (codified at 42 U.S.C. 12805 note);

15. Technical Assistance and Capacity Building awards authorized under any program or matter delegated under Section A (*e.g.,* section 107 of the Housing and Community Development Act of 1987, Public Law 100–242, 101 Stat. 1815 (1988)) and as provided for in annual and supplemental HUD appropriations acts (*e.g.,* the Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3093 (2009));

16. Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*); 24 CFR part 570, including the following:

a. The Community Development Block Grant (CDBG) program;

b. The Section 108 loan guarantee program;

c. Economic development grants pursuant to Section 108(q);

d. Neighborhood Stabilization programs under the Housing and Economic Recovery Act of 2008, Public Law 110–289, 122 Stat. 2850; Title XII of Division A of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115; and Section 1497 of the Wall Street Reform and Consumer Protection Act of 2010, Public Law 111–203, 124 Stat. 1376 (codified as amended at 42 U.S.C. 5301 note);

e. CDBG Disaster Recovery Grants as provided for in annual and supplemental HUD appropriations acts; and

f. Appalachian Regional Commission grants pursuant to section 214 of the Appalachian Regional Development Act of 1965, Public Law 89–4, 79 Stat. 5 (codified as amended at 40 U.S.C. 14507) and consistent with the CDBG program authorized under Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*).

17. Title IV of the McKinney-Vento Homeless Assistance Act, Public Law 100–

77, 101 Stat. 482 (1987) (codified as amended at 42 U.S.C. 11301 *et seq.*), *renamed by* an Act of October 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000), including the following:

a. The Emergency Shelter Grants/ Emergency Solutions Grants program, 24 CFR part 576;

b. The Supportive Housing Program, 24 CFR part 583;

c. The Shelter Plus Care Program, 24 CFR part 582;

d. The Moderate Rehabilitation for Single Room Occupancy program, 24 CFR part 882, Subpart H;

e. The Continuum of Care program; and

f. The Rural Housing Stability Assistance program.

18. Title V of the McKinney-Vento Homeless Assistance Act, Public Law 100–77, 101 Stat. 482 (1987) (codified as amended 42 U.S.C. 11411 *et seq.*), *renamed by* an Act of October 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000), 24 CFR part 581.

19. The Veterans Homelessness Prevention Demonstration program, as provided for in annual HUD appropriations act(s) (*e.g.,* Omnibus Appropriations Act, 2009, Public Law 111–8, 123 Stat. 524 (2009)).

20. Overall departmental responsibility for compliance with the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970, Public Law 91–646, 84 Stat. 1894 (1971) (codified as amended at 42 U.S.C. 4601 *et seq.*); 49 CFR part 24 (For departmental programs, only the Assistant Secretary for Community Planning and Development is delegated the authority to exercise the federal agency waiver authority provided under 49 CFR 24.7).

21. Overall departmental responsibility for compliance with the National Environmental Policy Act of 1969, Public Law 91–190, 83 Stat. 852 (1970) (codified as amended at 42 U.S.C. 4321–4347), and the related laws and authorities cited in 24 CFR 50.4, including (with regard to the Assistant Secretary for Community Planning and Development) the authority to issue and to waive, or approve exceptions or establish criteria for exceptions from provisions of, 24 CFR parts 50, 51, 55, and 58.

22. Certain Office of Community Planning and Development programs that are no longer authorized for funding (or future funding is not anticipated), but whose administration must continue until all departmental responsibilities are discharged and finally terminated. These programs, as of September 2011, include the following:

a. The Slum Clearance and Urban Renewal program under Title I of the Housing Act of 1949, Public Law 81–171, 63 Stat. 413 and any program which is superseded by, or inactive by reason of Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5316);

b. Area-wide grants, inequities grants, disaster grants and the authority to concur in final approval actions regarding innovative grants under section 107 of Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (repealed 1981);

c. Urban Development Action grants under Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5318);

d. The Rental Rehabilitation Program, United States Housing Act of 1937, § 17, Public Law 98–181, 97 Stat. 1196 (repealed 1990); 24 CFR part 511;

e. The Section 312 Rehabilitation Loan Program, Housing Act of 1964, § 312, Public Law 88–560, 78 Stat. 769 (codified at 42 U.S.C. 1452(b)); 24 CFR part 510;

f. The Urban Homesteading Program, Housing and Community Development Act of 1974, § 810, Public Law 93–383, 88 Stat. 633 (repealed 1990);

g. Enterprise Zone Program under Title VII of the Housing and Community Development Act of 1987, Pub. L. No 100–242, 101 Stat. 1815 (1988) (codified as amended at 42 U.S.C. 11501 *et seq.*);

h. Grants for urban Empowerment Zones (EZ) as provided for in annual HUD appropriations acts (*e.g.,* Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003));

i. HUD's Homeownership Zone Initiative (HOZ) grants as provided for in section 205 of the Departments of Veterans Affairs and Housing and Urban Development, and Independent Agencies Appropriations Act, 1997, Public Law 104–204, 110 Stat. 2874 (1996) and funded with recaptured Nehemiah grants authorized under Title VI of the Housing and Community Development Act of 1987, Public Law 100–242, 101 Stat. 1815 (1988) (codified at 12 U.S.C. 1715l note);

j. The Innovative Homeless Initiatives Demonstration program under the HUD Demonstration Act of 1993, Public Law 103–120, 107 Stat. 1144;

k. The HOPE for Homeownership of Single-family Housing (HOPE 3) program, Title IV, Subtitle C of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified at 42 U.S.C. 12891);

l. New Communities Program, Section 413 of the Housing and Urban Development Act of 1968, Public Law 90–448, 82 Stat. 476 (repealed 1983), Section 726 of the Housing and Urban Development Act of 1970, Public Law 91–609 (repealed 1983), 84 Stat. 1784, Section 474 of the Housing and Urban-Rural Recovery Act of 1983, Public Law 98–181, 97 Stat. 1237 (codified at 12 U.S.C. 1701g–5b), and any other functions, powers, and duties that may affect the liquidation of the New Communities program;

m. Rural Housing and Economic Development grants specifically designated originally in the Fiscal Year 1998 HUD Appropriations Act, Public Law 105–65, 111 Stat. 1344 and subsequent annual HUD appropriations acts;

n. Renewal Communities (RC)), as authorized under title 26, subtitle A, chapter 1, subchapter X of the Internal Revenue Code (codified as amended at 26 U.S.C. 1400E *et seq.*); 24 CFR part 599.

o. The Youthbuild Program, Title IV, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (repealed 2006); 24 CFR part 585; and Youthbuild Transfer Act (TA) as authorized under Title IV of the Cranston-Gonzalez National Affordable Housing Act, as amended by the Housing and Community Development Act of 1992, Public Law 102–550, 106 Stat. 3723 (1992) (repealed 2006); and

p. All programs consolidated in the Revolving Fund (Liquidating Programs) established pursuant to Title II of the Independent Offices Appropriations Act, Public Law 98–45, 97 Stat. 223 (1983) (codified as amended at 12 U.S.C. 1701g–5), including all authority of the Secretary with respect to functions, administration, and management of the Revolving Fund (Liquidating Programs). Only the Assistant Secretary is the responsible official for allotments in the Revolving Fund (Liquidating Programs); and

23. Debarments, suspensions, and/or limited denial of participations under 2 CFR part 2424 with the concurrence of the General Counsel, or such other official as may be designated by the General Counsel.

Section B. Authority Excepted

There is excepted from the authority delegated under Section A:

1. The power to sue and be sued;

2. Under Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*):

a. The power to administer the Indian Community Development Block Grant program, for which the authority has been delegated to the Assistant Secretary for Public and Indian Housing;

b. The power to administer section 107 programs delegated to the Assistant Secretary for Policy Development and Research;

c. The power to issue obligations for purchase by the Secretary of the Treasury under section 108(g) of the Housing and Community Development Act (42 U.S.C. 5308); and

d. The power and authority of the Secretary with respect to nondiscrimination under section 109 may be exercised only with the advice of the Assistant Secretary for Fair Housing and Equal Opportunity.

3. Under the HOME Investment Partnerships Act, Title II of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12721 *et seq.*), the power to administer grants to Indian tribes, for which the authority has been delegated to the Assistant Secretary for Public and Indian Housing; and

4. For programs noted in Section A.22 of this delegation that are no longer authorized for funding:

a. The power to establish interest rates; and

b. The power to issue notes or obligations for purchase by the Secretary of the Treasury.

Section C. Authority To Redelegate

The Assistant Secretary may not redelegate the authority to issue or waive regulations covered by section 7(q) of the Department of Housing and Urban Development Act, 42 U.S.C. 3535(q). *See Waiver of Regulations Issued by HUD, Restatement of Policy,* 73 FR 76674 (Dec. 17, 2008). The

Assistant Secretary, the General Deputy Assistant Secretary for Community Planning and Development, and the Deputy Assistant Secretary for Grant Programs are authorized to redelegate to employees of the Department any other authority delegated under Section A. Redelegated authority to CPD Deputy Assistant Secretaries or other CPD program officials does not supersede the authority of the Assistant Secretary as designee of the Secretary.

Section D. Delegations Superseded

This notice supersedes all prior delegations of authority from the Secretary to the Assistant Secretary, the General Deputy Assistant Secretary for Community Planning and Development, and the Deputy Assistant Secretary for Grant Programs.

Section E. Actions Ratified

The Secretary hereby ratifies all actions previously taken by the Assistant Secretary, the General Deputy Assistant Secretary for Community Planning and Development, the Deputy Assistant Secretary for Grant Programs, and the Deputy Assistant Secretary for Grant Programs, with respect to the programs and matters listed in Section A.

Authority: Section 7(d) of the Department of Housing and Urban Development Act, 42 U.S.C. 3535(d).

Dated: October 4, 2011.

Shaun Donovan,

Secretary.

[FR Doc. 2011–26909 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5556–D–02]

Order of Succession for the Office of Community Planning and Development

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice of Order of Succession.

SUMMARY: In this notice, the Assistant Secretary for Community Planning and Development designates the Order of Succession for the Office of Community Planning and Development. This Order of Succession supersedes all prior Orders of Succession for the Assistant Secretary for Community Planning and Development, including the notice published on October 18, 2006.

DATES: *Effective Date:* October 4, 2011.

FOR FURTHER INFORMATION CONTACT: David H. Enzel, Director, Office of Technical Assistance and Management, Department of Housing and Urban Development, 451 7th Street, SW., Room 7228, Washington, DC 20410, telephone number 202–402–5557. (This is not a toll-free number.) This number may be accessed via TTY by calling the Federal Relay Service at 800–877–8339 (this is a toll-free number).

SUPPLEMENTARY INFORMATION: The Assistant Secretary is issuing this Order of Succession of officials authorized to perform the functions and duties of the Office of the Assistant Secretary for Community Planning and Development when, by reason of absence, disability, or vacancy in office, the Assistant Secretary is not available to exercise the powers or perform the duties of the office. This Order of Succession is subject to the provisions of the Federal Vacancies Reform Act of 1998 (5 U.S.C. 3345–3349d). This publication supersedes all prior Orders of Succession for the Office of Community Planning and Development, including the notice of October 18, 2006 (71 FR 61499).

Accordingly, the Assistant Secretary designates the following Order of Succession:

Section A. Order of Succession

Subject to the provisions of the Federal Vacancies Reform Act of 1998, during any period when, by reason of absence, disability, or vacancy in office, the Assistant Secretary is not available to exercise the powers or perform the duties of the Assistant Secretary for Community Planning and Development, the following officials within the Office of Community Planning and Development are hereby designated to exercise the powers and perform the duties of the Office, including the authority to waive regulations:

(1) Deputy Assistant Secretary for Grant Programs.

(2) General Deputy Assistant Secretary for Community Planning and Development.

(3) Deputy Assistant Secretary for Operations.

(4) Deputy Assistant Secretary for Special Needs.

(5) Deputy Assistant Secretary for Economic Development.

These officials shall perform the functions and duties of the office in the order specified herein, and no official shall serve unless all the other officials, whose position titles precede his/hers in this order, are unable to act by reason of absence, disability, or vacancy in office.

Section B. Authority Superseded

This Order of Succession supersedes all prior Orders of Succession for the Assistant Secretary for Community Planning and Development, including the notice published at 71 FR 61499 (October 18, 2006).

Authority: Section 7(d), Department of Housing and Urban Development Act, 42 U.S.C. 3535(d).

Dated: October 4, 2011.

Mercedes M. Márquez,

Assistant Secretary for Community Planning and Development.

[FR Doc. 2011–26910 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5556–D–03]

Redelegations of Authority to Directors and Deputy Directors of Community Planning and Development in Field Offices

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice of redelegation of authority to field offices.

SUMMARY: In this notice, the Assistant Secretary of Community Planning and Development redelegates to the Directors and Deputy Directors of Community Planning and Development in HUD Field Offices all powers and authorities necessary to carry out Office of Community Planning and Development programs, except those powers and authorities specifically excluded.

DATES: *Effective Date:* October 4, 2011.

FOR FURTHER INFORMATION CONTACT: David H. Enzel, Director of Technical Assistance and Management, Office of Community Planning and Development, Department of Housing and Urban Development, 451 7th Street, SW., Room 7228, Washington, DC 20410–7000; telephone number 202–402–5557. This is not a toll-free number. For those needing assistance, this number may be accessed via TTY by Calling the Federal Relay Service at 800 877–8339.

SUPPLEMENTARY INFORMATION: This notice updates and revises redelegations of authority from the Assistant Secretary for Community Planning and Development (CPD) to CPD Directors and Deputy Directors in HUD Field Offices. This notice supersedes all previous redelegations of authority to CPD Directors and Deputy Directors in HUD Field Offices, including a

redelegation published on April 26, 2006 (71 FR 24736). Published elsewhere in today's **Federal Register** is a revised consolidated delegation of authority from the Secretary of HUD to the Assistant Secretary. the General Deputy Assistant Secretary for CPD, and the Deputy Assistant Secretary for Grant Programs. Also published elsewhere in today's **Federal Register** is a redelegation of authority from the Assistant Secretary for CPD to subordinate Headquarters officials within CPD.

Section A. General Redelegation of Authority

Except those authorities specifically excluded, the Assistant Secretary redelegates to the Directors and Deputy Directors of Community Planning and Development in HUD Field Offices all powers and authorities of the Assistant Secretary necessary to carry out the following Community Planning and Development programs and matters:

1. Community Development Block Grants (CDBG), Section 108 Loan Guarantees, Neighborhood Stabilization Programs (NSP), CDBG Disaster Recovery Grants, and other programs covered by Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*); 24 CFR part 570.

Authority not redelegated:

a. Terminate, reduce or limit the availability of grant payments pursuant to section 111(a), 42 U.S.C. 5311.

b. Adjust entitlement and state grants pursuant to section 104(e), 42 U.S.C. 5304.

c. Determine basic grant amounts for metropolitan cities, urban counties, and States pursuant to section 106, 42 U.S.C. 5306.

d. Reallocate funds pursuant to section 106(c) or (d), 42 U.S.C. 5306.

e. Determine the qualifications of localities for special consideration. This includes, but is not limited to, the determination of qualifications of counties as urban counties pursuant to section 102(a)(6), 42 U.S.C. 5302, the determination of what constitutes a city pursuant to section 102(a)(5), 42 U.S.C. 5302, and the determination of levels of physical and economic distress of cities and urban counties for eligibility for urban development action grants pursuant to section 119(b), 42 U.S.C. 5318.

f. Approve and disapprove applications, or amendments to applications, filed for loan guarantee or grant assistance, issue commitments or grant awards, execute grant agreements, or issue guarantees pursuant to section 108, 42 U.S.C. 5308.

2. Comprehensive Housing Affordability Strategies (CHAS), Title I of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12701 *et seq.*); 24 CFR part 91.

3. Emergency Shelter Grants/ Emergency Solutions Grants program, Title IV, Subtitle B of the McKinney-Vento Homeless Assistance Act, Public Law 100–77, 101 Stat. 482 (1987) (codified as amended at 42 U.S.C. 11371 *et seq.*), renamed by Act of Oct. 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000); 24 CFR part 576.

Authority not redelegated:

a. Determine allocation amounts.

b. Approve built-in waivers or exceptions authorized under Title IV of the McKinney- Vento Homeless Assistance Act and applicable implementing regulations (such as section 414(b), 42 U.S.C. 11374(b); 24 CFR 576.21(b)(2) and section 415(d), 42 U.S.C. 11375(d); 24 CFR 576.56(b); 24 CFR 576.57(d).

4. The HOME Investment Partnerships Act, Title II of the Cranston-Gonzalez National Affordable Housing Act (NAHA), Public Law 101–625, 104 Stat. 4094 (1990) (codified as amended at 42 U.S.C. 12721 *et seq.*); 24 CFR part 92.

Authority not redelegated:

a. Determine allocation and reallocation amounts pursuant to section 217 of NAHA.

b. Revoke a jurisdiction's designation as a participating jurisdiction pursuant to section 216 of NAHA.

c. Effect remedies for noncompliance pursuant to section 223 of NAHA.

d. Approve a change in the number of units designated as HOME-assisted units during the period of affordability pursuant to 24 CFR 92.205(d).

e. Make a determination that a consortium does not have sufficient authority and administrative capability to administer the HOME Program pursuant to 24 CFR 92.101(a)(3).

5. Housing Trust Fund (HTF), Section 1338 of the Federal Housing Enterprises Financial Safety and Soundness Act of 1992, added by Section 1131 of Public Law 110–289, 122 Stat. 2654 (codified at 12 U.S.C. 4568).

Authority not redelegated:

a. Determine allocations, adjustments and reallocation amounts.

6. Homelessness Prevention and Rapid Re-Housing Program (HPRP) as authorized under the Homelessness Prevention Fund heading of Division A, Title XII of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115.

7. AIDS Housing Opportunity Act, Title VIII, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12901–12912); 24 CFR part 574.

Authority not redelegated:

a. Determine allocations, adjustments and reallocation amounts.

b. Revoke a jurisdiction's designation as an eligible state or eligible metropolitan statistical area for a formula allocation or as an eligible applicant for a nonformula allocation.

c. Suspend or terminate current awards in whole or in part, withhold further awards, and effect other legally available remedies pursuant to 24 CFR 85.43(a)(3), (4) and (5).

d. Approve built-in waivers pursuant to section 858, 42 U.S.C. 12907(b)(1)(B); 24 CFR 574.310(c)(2).

8. Title IV Subtitles C–F of the McKinney-Vento Homeless Assistance Act, Public Law 100–77, 101 Stat. 482 (1987) (codified as amended at 42 U.S.C. 11381 *et seq.*), renamed by Act of Oct. 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000) including the following: Supportive Housing Program, 24 CFR part 583, Shelter Plus Care program, 24 CFR part 582, Moderate Rehabilitation for Single Room Occupancy program, 24 CFR part 882, Subpart H, Continuum of Care program, and Rural Housing Stability Assistance program.

Authority not redelegated:

a. Make funding decisions.

b. Approve built-in waivers or exceptions authorized under Title IV of the McKinney-Vento Homeless Assistance Act and applicable implementing regulations (such as section 426(g), 42 U.S.C. 11386(g); 24 CFR 583.300(f); section 455(c), 42 U.S.C. 11403d(c); 24 CFR 582.300(a); section 441(h), 42 U.S.C. 11401(h); 24 CFR 882.808(q); 24 CFR 582.340(b); 24 CFR 583.330(e)).

9. Economic Development Initiative grants, as provided for in annual HUD appropriations acts (e.g., Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003)).

10. Neighborhood Initiatives grants specifically designated in annual HUD appropriations acts (e.g., Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3034 (2009)).

11. Rural Innovation Fund grants as provided for in annual HUD appropriations act(s) (e.g., Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3084 (2009)).

12. The urban Empowerment Zones (EZ), as authorized under title 26, subtitle A, chapter 1, subchapter U of the Internal Revenue Code (codified as

amended at 26 U.S.C. 1391 *et seq.*); 24 CFR parts 597 and 598.

Authority not redelegated:

a. Approve or amend strategic plans or other state and local commitments, including boundary changes.

b. Revoke a designation, including issuing a warning letter pursuant to 24 CFR parts 597 and 598.

13. Overall Departmental responsibility for compliance with the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970, Public Law 91–646, 84 Stat. 1894 (1971) (codified as amended at 42 U.S.C. 4601 *et seq.*); 49 CFR part 24.

Authority not redelegated:

a. Exercise the Federal Agency waiver authority provided under 49 CFR 24.7.

14. Technical Assistance and Capacity Building awards authorized under any program or matter delegated under Section A (e.g., section 107 of the Housing and Community Development Act of 1987, Public Law 100–242, 101 Stat. 1815 (1988)) and as provided for in annual and supplemental HUD appropriations acts (e.g., Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3093 (2009)).

15. Certain Community Planning and Development programs that are no longer authorized for funding (or future funding is not anticipated) but administration of the programs must continue until all Department responsibilities are discharged and finally terminated. These programs, as of June 2011, include the following:

a. Any program superseded by, or inactive by reason of, Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5316).

b.Grants for urban Empowerment Zones (EZ) as provided for in annual HUD appropriations acts (e.g., Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003)).

c. HOPE for Homeownership of Single-family Housing Program (HOPE 3), Title IV, Subtitle C of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified at 42 U.S.C. 12891).

d. New Communities Program, Section 413 of the Housing and Urban Development Act of 1968, Public Law 90–448, 82 Stat. 476 (repealed 1983), Section 726 of the Housing and Urban Development Act of 1970, Public Law 91–609 (repealed 1983), 84 Stat. 1784, Section 474 of the Housing and Urban-Rural Recovery Act of 1983, Public Law 98–181, 97 Stat. 1237 (codified at 12 U.S.C. 1701g–5b), and any other functions, powers and duties which may affect the liquidation of the New Communities program.

e. Rural Housing and Economic Development grants specifically designated originally in the Fiscal Year 1998 HUD Appropriations Act, Public Law 105–65, 111 Stat. 1344 (1997), and subsequent annual HUD appropriations acts.

f. Renewal Communities (RC), as authorized under Title 26, Subtitle A, Chapter 1, Subchapter X of the Internal Revenue Code (codified as amended at 26 U.S.C. 1400E *et seq.*); 24 CFR part 599.

g. All programs consolidated in the Revolving Fund (Liquidating Programs) established pursuant to Title II of the Independent Offices Appropriations Act, Public Law 98–45, 97 Stat. 223 (1983) (codified as amended at 12 U.S.C. 1701g–5)) including all authority of the Assistant Secretary with respect to the functions, administration and management of the Revolving Fund (Liquidating Programs). Only the Assistant Secretary is the responsible official for allotments in the Revolving Fund (Liquidating Programs).

h. Youthbuild Program, Title IV, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (repealed 2006); 24 CFR part 585; and Youthbuild TA as authorized under Title IV of the Cranston-Gonzalez National Affordable Housing Act, as amended by the Housing and Community Development Act of 1992, Public Law 102–550, 106 Stat. 3723 (1992) (repealed 2006).

Section B. Limited Denial of Participation

Subject to the excepted authority in Section C, the Assistant Secretary redelegates to Directors and Deputy Directors of CPD in HUD Field Offices the authority to order a limited denial of participation sanction pursuant to HUD regulations at 2 CFR part 2424, with respect to the programs and matters listed in Section A; provided that the General Counsel, or such other official as may be designated by the General Counsel, must: (1) Concur in any proposed sanction under 2 CFR part 2424 before it is issued, and (2) concur in any proposed settlement of a sanction under 2 CFR part 2424.

Section C. General Authority Excepted

The authority redelegated under Section A does not include:

1. The authority to issue or waive regulations covered by section 7(q) of the Department of Housing and Urban Development Act (42 U.S.C. 3535(q));

2. The authority to sue and be sued;

3. The authority to effect remedies for noncompliance requiring notice and an opportunity for an administrative hearing;

4. The authority for allotments in the Revolving Fund (Liquidating Programs) under paragraph g of Section A; or

5. Any authority not delegated to the Assistant Secretary for CPD under the Consolidated Delegation of Authority for Community Planning and Development.

The Assistant Secretary may revoke at any time this redelegation with respect to the programs and matters listed in Section A and orders of limited denial of participation issued in accordance with Section B.

Section D. Authority to Further Redelegate

The authority redelegated in Sections A and B may not be further redelegated.

Section E. Redelegations Superseded

This notice supersedes all prior redelegations of authority from the Assistant Secretary of CPD to Directors and Deputy Directors of Community Planning and Development in HUD Field Offices.

Section F. Actions Ratified

The Assistant Secretary hereby ratifies all actions previously taken by the Directors and Deputy Directors of CPD in HUD Field Offices, from April 26, 2006, through the effective date of this document by the Secretary, with respect to the programs and matters listed in Section A and orders of limited denial of participation issued in accordance with Section B.

Authority: Section 7(d), Department of Housing and Urban Development Act, 42 U.S.C. 3535(d).

Dated: October 4, 2011.

Mercedes M. Márquez,

Assistant Secretary.

[FR Doc. 2011–26911 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5486–N–23]

Notice of Proposed Information Collection for Public Comment: Additional On-Site Data Collection for the Housing Choice Voucher Program Administrative Fee Study

AGENCY: Office of the Policy Development and Research, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below

will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: Comments Due Date: *December 19, 2011.*

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control number and should be sent to: Reports Liaison Officer, Office of Policy Development & Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8226, Washington, DC 20410–5000.

FOR FURTHER INFORMATION CONTACT: Marina L. Myhre, (202) 402–5705 for copies of the proposed forms and other available documents. (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION: The Department will submit the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35, as amended). This Notice is soliciting comments from members of the public and affected agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated collection techniques or other forms of information technology (*e.g.,* permitting electronic submission of responses).

This Notice also lists the following information:

Title of Proposal: Housing Choice Voucher Program Administrative Fee Study.

Description of the need for the information and proposed use: This request is for the clearance of on-site data collection from public housing agencies (PHAs). The purpose of the proposed data collection is to identify a sample of PHAs that are verified to be operating high-performing and efficient HCV programs. The proposed data collection will take place through site visits to up to 30 PHAs and will include interviews with PHA staff and reviews of client files and administrative data collected by the PHA. The results of the site visits will be used to identify PHAs to participate in a national study of administrative fees in the HCV program. The national study of administrative fees will include 50 PHAs, some of which have already been identified through site visits that took place at 60 PHAs between April and September 2011. The current request is to conduct similar data collection at a new group of PHAs to supplement the national study sample. The results of the national study—for which separate OMB clearance will be sought—will be used to estimate administrative fees and develop a new administrative fee allocation formula for the HCV program.

OMB Approval Number: Pending.

Agency form numbers: None.

Members of Affected Public: Up to 150 public housing agency staff persons (up to 5 staff members at up to 30 sites).

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: Up to 5 PHA staff at each of the 30 study sites will be involved in the data collection (150 respondents total). Together, the PHA staff at each site will spend up to 12 hours preparing for the site visit and up to 16 hours being interviewed or otherwise assisting the research team during the site visit. The total burden for each PHA is 28 hours. The total estimated burden across all PHAs is 840 hours.

Status of the proposed information collection: Pending OMB approval.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. chapter 35, as amended.

Dated: October 11, 2011.

Raphael W. Bostic,

Assistant Secretary for Policy, Development and Research.

[FR Doc. 2011–26918 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

Docket No. FR–5486–N–24]

Notice of Proposed Information Collection for Public Comment: Pre-Purchase Homeownership Counseling Demonstration and Impact Evaluation

AGENCY: Office of the Policy Development and Research, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: Comments Due Date: *December 19, 2011.*

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control number and should be sent to: Reports Liaison Officer, Office of Policy Development & Research, Department of Housing and Urban Development, 451 7th Street, SW., Room 8226, Washington, DC 20410–5000.

FOR FURTHER INFORMATION CONTACT: Marina L. Myhre, (202) 402–5705 for copies of the proposed forms and other available documents. (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION: The Department will submit the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35, as amended). This Notice is soliciting comments from members of the public and affected agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated collection techniques or other forms of information technology (*e.g.,* permitting electronic submission of responses).

This Notice also lists the following information:

Title of Proposal: Pre-Purchase Homeownership Counseling Demonstration and Impact Evaluation.

Description of the need for the information and proposed use: This request is for the clearance of data collection instruments designed to collect the information necessary to conduct a random assignment evaluation of pre-purchase homeownership counseling. The evaluation will produce valuable information about the impact of pre-purchase homeownership counseling on a range of outcomes for low- to moderate-income first-time FHA home buyers. Four thousand study

participants will be enrolled through the branch offices and telephone centers of three national lenders in 10 jurisdictions throughout the country. Lender staff will ask potential home buyers to voluntarily participate in the study, directing interested participants to the telephone call-in research center for the eligibility assessment and baseline survey. To achieve 4,000 enrolled study participants, the intake and eligibility assessment will be conducted with up to 7,000 potential study participants over a period of 9 to 10 months. Additionally, 45 study participants will be asked to participate in semi-structured follow-up interviews that seek to learn about participants' experiences with enrollment and interaction with participating counseling agencies.

In each of the 10 jurisdictions for the study, local counseling agencies and national counseling intermediaries will be recruited to provide (a) Online education and telephone counseling and (b) in-person education and counseling. One national provider will be responsible for the online education and telephone counseling. Local counseling agencies will be recruited to provide the in-person education and counseling. In each case, the counseling agencies will be responsible for documenting the counseling services provided to the 2,300 study participants assigned to receive one of these types of counseling (the remaining 1,700 study participants constitute the control group). Staff of the lenders and counseling agencies will be asked to participate in semi-structured interviews that seek to understand the enrollment process and provision of counseling in each jurisdiction. The purpose of these data collection activities is to collect the information needed to evaluate the impact of pre-purchase housing counseling.

OMB Approval Number: Pending.

Agency form numbers: None.

Members of Affected Public: Up to 7,000 potential first-time homebuyers; Up to 30 counseling organizations; and, up to 1500 lender staff in 10 jurisdictions.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: The average time per client for the 7,000 potential study participants to complete the intake and eligibility assessment is 10 minutes. The average time per client for the 4,000 enrolled study participants to complete the baseline survey is 25 minutes. The average time per client for the follow-up interviews is 30 minutes. The average time per client for counseling agencies to document the services provided to study participants is 10 minutes, with responses required for both the educational component and for the counseling services. The average time for counseling agency staff to complete interviews is 60 minutes—up to 8 interviews conducted at up to 30 counseling organizations. The average time per client for lender staff to input the intake information is 3 minutes, with intake conducted with up to 7,000 potential study participants. The total burden for the study is 4,274 hours: 2,857 hours for study participants and potential study participants, 1,007 hours for counseling agencies, and 410 hours for lenders.

Status of the proposed information collection: Pending OMB approval.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Dated: October 11, 2011.

Raphael W. Bostic,

Assistant Secretary for Policy Development and Research.

[FR Doc. 2011–26919 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5486–N–25]

Notice of Submission of Proposed Information Collection to OMB Homelessness Prevention Study

AGENCY: Office of Policy Development and Research, HUD.

ACTION: Notice.

SUMMARY: The Department of Housing and Urban Development requests review and approval of the Paperwork Reduction Act requirements for site visits that are part of HUD's Homelessness Prevention Study. The proposed information collection was approved under emergency review (OMB Control #2528–0270). As required by the Paperwork Reduction Act, the proposed information collection will be submitted to the Office of Management and Budget (OMB) for full review and extension of approval. The Department is soliciting public comments on the proposed collection of information to: (1) Enhance the quality, utility, and clarity of the information to be collected; and (2) minimize the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology that will reduce burden (*e.g.,* permitting electronic submission of responses).

DATES: *December 19, 2011.*

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments must be received within sixty (60) days from the date of this Notice. Comments should refer to the proposal by name or OMB approval number and should be sent to: Reports Liaison Officer, Office of Policy Development and Research, Department of Housing and Urban Development, 451 Seventh Street, SW., Room 8230, Washington, DC 20410.

FOR FURTHER INFORMATION CONTACT: Elizabeth Rudd, Department of Housing and Urban Development, 451 7th Street, SW., Room 8120, Washington, DC 20410; e-mail *Elizabeth.C.Rudd@hud.gov;* or telephone 202–402–7607. This is not a toll-free number. Copies of documents submitted to OMB may be obtained from Dr. Rudd.

SUPPLEMENTARY INFORMATION: This Notice informs the public that the U.S. Department of Housing and Urban Development (HUD) has submitted to OMB a request to extend approval for information collection for the Homelessness Prevention study that was already approved under emergency review (OMB Control #2528–0270). HUD requests extension of approval for the site visit interview guide.

Congress established the Homelessness Prevention and Rapid Re-Housing Program (HPRP) under the American Recovery and Reinvestment Act of 2009 (ARRA) to provide resources to state and local governments to aid households at risk of homelessness maintain stable housing and to help currently homeless households get back into permanent housing quickly. HUD allocated $1.5 billion to 535 government agency grantees (55 states and territories, 147 counties, and 333 cities) to be spent over three years. HUD funded the *Homelessness Prevention Study* to study the prevention programs established by communities with HPRP funds. The study includes a survey of a nationally representative sample of HPRP grantees and 15–18 site visits to selected HPRP grantees.

Title of Proposed Notice: Homelessness Prevention Study.

Description of Information Collection: This is a request to extend approval granted under emergency review (OMB Control # 2528–0270) that expires on January 1, 2012. Administration of the survey and half of the site visits will be completed before the current OMB approval expires. Therefore, this request to extend approval applies only to the collection of information during 7–8 site

visits at HPRP-funded homelessness prevention programs.

OMB Control Number: 2528–0270.

Agency Form Numbers: None.

Members of Affected Public: Selected HPRP grantees who agree to participate in the site visits for the evaluation.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of responses, and hours of responses: The estimated number of respondents in the site visits is approximately 62 individuals; the frequency of the response is once; and the total reporting burden will be approximately 46.5 hours.

Authority: The Paperwork Reduction Act of 1995, 44 U.S.C. chapter 35, as amended.

Dated: October 7, 2011.

Raphael W. Bostic,

Assistant Secretary for Policy Development and Research.

[FR Doc. 2011–26922 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5480–N–103]

Notice of Submission of Proposed Information Collection to OMB Annual Progress Reports for Empowerment Zones

AGENCY: Office of the Chief Information Officer, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below has been submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

The primary purpose of this collection is to continue current data reporting for Rounds, I, II, and III Empowerment Zones (EZs). HUD previously designated 30 EZs, which required to submit annual reports to HUD based on the progress reported in implementing the EZs' strategic plans. Businesses located in the EZs are eligible for Federal tax incentives to hire local residents and to expand or improve their operations. This is an extension of a currently approved collection.

DATES: *Comments Due Date:* November 17, 2011.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB approval Number (2506–0148) and should be sent to: HUD Desk Officer, Office of Management and Budget, New Executive Office Building, Washington, DC 20503; e-mail *OIRA–Submission@omb.eop.gov fax:* 202–395–5806.

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, QDAM, Department of Housing and Urban Development, 451 Seventh Street, SW., Washington, DC 20410; e-mail Colette Pollard at *Colette.Pollard@hud.gov;* or telephone (202) 402–3400. This is not a toll-free number. Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

SUPPLEMENTARY INFORMATION: This notice informs the public that the Department of Housing and Urban Development has submitted to OMB a request for approval of the Information collection described below. This notice is soliciting comments from members of the public and affecting agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

This notice also lists the following information:

Title of Proposal: Annual Progress Reports for Empowerment Zones.

OMB Approval Number: 2506–0148.

Form Numbers: None.

Description of the Need for the Information and its Proposed Use:

The primary purpose of this collection is to continue current data reporting for Rounds, I, II, and III Empowerment Zones (EZs). HUD previously designated 30 EZs, which required to submit annual reports to HUD based on the progress reported in implementing the EZs' strategic plans. Businesses located in the EZs are eligible for Federal tax incentives to hire local residents and to expand or improve their operations. This is an extension of a currently approved collection.

Frequency of Submission: On Occasion, Annually.

	Number of respondents	Annual responses	×	Hours per response	=	Burden hours
Reporting Burden	75	1		5.506		413

Total Estimated Burden Hours: 413.

Status: Extension without change of a previously approved collection.

Authority: Section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. 35, as amended.

Dated: October 11, 2011.

Colette Pollard,

Departmental Reports Management Officer, Office of the Chief Information Officer.

[FR Doc. 2011–26917 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. 5556–D–04]

Redelegation of Authority for the Deputy Assistant Secretaries in the Office of Community Planning and Development

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice of redelegation of authority to Deputy Assistant Secretaries in Community Planning and Development.

SUMMARY: In this notice, the Assistant Secretary of Community Planning and Development redelegates to the Deputy Assistant Secretaries and other specified HUD officials all powers and authorities necessary to carry out Office of Community Planning and Development programs, except those powers and authorities specifically excluded.

DATES: *Effective Date:* October 4, 2011 .

FOR FURTHER INFORMATION CONTACT: David H. Enzel, Director of Technical

Assistance and Management, Office of Community Planning and Development, Department of Housing and Urban Development, 451 7th Street, SW., Room 7228, Washington, DC 20410–7000; telephone number 202 402–5557. This is not a toll-free number. For those needing assistance, this number may be accessed via TTY by Calling the Federal Information Relay Service at 800–877–8339.

SUPPLEMENTARY INFORMATION: Published elsewhere in today's **Federal Register** is a revised consolidated delegation of authority from the Secretary to the Assistant Secretary for Community Planning and Development and the General Deputy Assistant Secretary for Community Planning and Development. This notice updates and revises redelegations of authority to Deputy Assistant Secretaries and other specified HUD officials within the Office of Community Planning and Development (CPD). Also published elsewhere in today's **Federal Register** is a redelegation of authority from the Assistant Secretary for Community Planning and Development to subordinate employees within CPD Field Offices.

Section A. General Redelegation of Authority

1. Deputy Assistant Secretary for Grant Programs

Except those authorities specifically excluded, the Assistant Secretary redelegates to the Deputy Assistant Secretary for Grant Programs all powers and authorities of the Assistant Secretary necessary to carry out the following Community Planning and Development programs and matters:

a. Comprehensive Housing Affordability Strategies (CHAS), Title I of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12701 *et seq.*); 24 CFR part 91.

b. The HOME Investment Partnerships Act, Title II of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12721 *et seq.*); 24 CFR part 92.

c. Housing Trust Fund (HTF), Section 1338 of the Federal Housing Enterprises Financial Safety and Soundness Act of 1992, added by Section 1131 of Public Law 110–289, 122 Stat. 2654 (codified at 12 U.S.C. 4568).

d. Tax Credit Assistance Program (TCAP) as authorized under the HOME Investments Partnership Program heading of Division A, Title XII of American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115, 220–21.

e. Self-Help Housing Opportunity Program (SHOP) under section 11 of the Housing Opportunity Program Extension Act of 1996, Pub. L. No. 104–120, 110 Stat. 834 (codified as amended at 42 U.S.C. 12805 note).

f. Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*); 24 CFR part 570 including:

(1) Community Development Block Grant (CDBG) program;

(2) Section 108 loan guarantee program;

(3) Economic development grants pursuant to Section 108(q);

(4) Neighborhood Stabilization Programs under Housing and Economic Recovery Act of 2008, Public Law 110–289, 122 Stat. 2850; Title XII of Division A of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115; and Section 1497 of the Wall Street Reform and Consumer Protection Act of 2010, Public Law 111–203, 124 Stat. 1376 (codified as amended at 42 U.S.C. 5301 note).

(5) CDBG Disaster Recovery Grants as provided for in annual and supplemental HUD appropriations acts; and

(6) Appalachian Regional Commission grants pursuant to section 214 of the Appalachian Regional Development Act of 1965, Public Law 89–4, 79 Stat. 5 (codified as amended at 40 U.S.C. 14507) and consistent with the CDBG program authorized under Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5301 *et seq.*).

g. Overall Departmental responsibility for compliance with the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970, Public Law 91–646, 84 Stat. 1894 (1971) (codified as amended at 42 U.S.C. 4601 *et seq.*); 49 CFR part 24 (except for the authority to exercise the Federal Agency waiver authority provided under 49 CFR 24.7).

h. Environment, overall Departmental responsibility for compliance with the National Environmental Policy Act of 1969, Public Law 91–190, 83 Stat. 852 (1970) (codified as amended at 42 U.S.C. 4321–4347), and the related laws and authorities cited in 24 CFR 50.4.

i. Slum Clearance and Urban Renewal Program under Title I of the Housing Act of 1949, Public Law 81–171, 63 Stat. 413 and any program which is superseded or inactive by, or inactive by reason of, Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5316).

j. Rental Rehabilitation Program, United States Housing Act of 1937 § 17, Public Law 98–181, 97 Stat. 1196 (repealed 1990); 24 CFR part 511.

k. Section 312 Rehabilitation Loan Program, Housing Act of 1964 § 312, Public Law 88–560, 78 Stat. 769; 24 CFR part 510.

l. HUD's Homeownership Zone Initiative (HOZ) grants as provided for in section 205 of the Departments of Veterans Affairs and Housing and Urban Development, and Independent Agencies Appropriations Act, 1997, Public Law 104–204, 110 Stat. 2874 (1996) and funded with recaptured Nehemiah grants authorized under Title VI of the Housing and Community Development Act of 1987, Public Law 100–242, 101 Stat. 1815 (1988) (codified at 12 USC 1715l note).

m. HOPE for Homeownership of Single-family Housing Program (HOPE 3), Title IV, Subtitle C of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified at 42 U.S.C. 12891).

n. New Communities Program, Section 413 of the Housing and Urban Development Act of 1968, Public Law 90–448, 82 Stat. 476 (repealed 1983), Section 726 of the Housing and Urban Development Act of 1970, Public Law 91–609 (repealed 1983), 84 Stat. 1784, Section 474 of the Housing and Urban-Rural Recovery Act of 1983, Public Law 98–181, 97 Stat. 1237 (codified at 12 U.S.C. 1701g–5b), and any other functions, powers and duties which may affect the liquidation of the New Communities program.

o. Technical assistance and capacity building awards authorized under any program or matter programs and matters listed in Section A.1 and as provided for in annual and supplemental HUD appropriations acts (*e.g.,* Consolidated Appropriations Act 2010, Pub. L. 111–117, 123 Stat. 3093 (2009)).

Further, in the absence of the Deputy Assistant Secretary for Grant Programs, the Assistant Secretary redelegates to the Director of the Office of Block Grant Assistance all powers and authorities of the Assistant Secretary necessary to carry out programs and matters listed in paragraphs f and i of Section A.1.

Further, in the absence of the Deputy Assistant Secretary for Grant Programs, the Assistant Secretary redelegates to the Director of the Office of Affordable Housing Programs all powers and authorities of the Assistant Secretary necessary to carry out programs and matters listed in paragraphs b, c, d, e, g, and l of Section A.1.

2. Deputy Assistant Secretary for Special Needs

Except those authorities specifically excluded, the Assistant Secretary redelegates to the Deputy Assistant Secretary for Special Needs all powers and authorities of the Assistant Secretary necessary to carry out the following Community Planning and Development programs and matters:

a. Title IV of the McKinney-Vento Homeless Assistance Act, Public Law 100–77, 101 Stat. 482 (1987) (codified as amended at 42 U.S.C. 11301 *et seq.*), *renamed by* Act of Oct. 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000), including the following: Emergency Shelter Grants/Emergency Solutions Grants Program, 24 CFR part 576; Supportive Housing program, 24 CFR part 583;Shelter Plus Care program, 24 CFR part 582; Moderate Rehabilitation for Single Room Occupancy program, 24 CFR part 882, Subpart H; Continuum of Care program; Rural Housing Stability Assistance program.

b. Base Closure, Base Closure Community Redevelopment and Homeless Assistance Act of 1994, Public Law 103–421, 108 Stat. 4352 (codified as amended at 10 U.S.C. 2687 note); 24 CFR part 586.

c. Homelessness Prevention and Rapid Re-Housing Program (HPRP), as authorized under the Homelessness Prevention Fund heading of Division A, Title XII of the American Recovery and Reinvestment Act of 2009, Public Law 111–5, 123 Stat. 115.

d. Title V of the McKinney-Vento Homeless Assistance Act, Public Law 100–77, 101 Stat. 482 (1987) (codified as amended 42 U.S.C. 11411 *et seq.*), *renamed by* Act of Oct. 30, 2000, Public Law 106–400, 114 Stat. 1675 (2000), 24 CFR part 581.

e. Veterans Homelessness Prevention Demonstration Program, as provided for in annual HUD appropriations act(s) (*e.g.,* Omnibus Appropriations Act, 2009, Public Law 111–8, 123 Stat. 524 (2009)).

f. AIDS Housing Opportunity Act, Title VIII, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified as amended at 42 U.S.C. 12901–12912); 24 CFR part 574.

Further, in the absence of the Deputy Assistant Secretary for Special Needs, the Assistant Secretary redelegates to the Director of the Office of Special Needs Programs all powers and authorities of the Assistant Secretary necessary to carry out programs and matters listed in paragraphs a, b, c, d, and e of Section A.2. Further, the Assistant Secretary redelegates to the Director of the Community Assistance Division the authority to sign notices of available properties and subsequent letters regarding the properties under Title V of the McKinney-Vento Homeless Assistance Act (codified as amended 42 U.S.C. 11411 *et seq.*).

Further, in the absence of the Deputy Assistant Secretary for Special Needs, the Assistant Secretary redelegates to the Director of the Office of HIV/AIDS Housing all powers and authorities of the Assistant Secretary necessary to carry out programs and matters listed in paragraph f of Section A.2.

3. Deputy Assistant Secretary for Economic Development

Except those authorities specifically excluded, the Assistant Secretary redelegates to the Deputy Assistant Secretary for Economic Development all powers and authorities of the Assistant Secretary necessary to carry out the following Community Planning and Development programs and matters:

a. Economic Development Initiative grants, as provided for in annual HUD appropriations acts (*e.g.,* Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003)).

b. Economic development grants pursuant to Section 108(q) of Title I of the Housing and Community Development Act of 1974 (as amended 42 U.S.C. 5301 *et seq.*).

c. Grants for urban Empowerment Zones (EZ) as provided for in annual HUD appropriations acts (*e.g.,* Consolidated Appropriations Resolution, Fiscal Year 2003, Public Law 108–7, 117 Stat. 11 (2003)).

d. The Loan Guarantee Recovery Program under Section 4 of the Church Arson Prevention Act of 1996, Public Law 104–155, 110 Stat. 1392 (codified at 18 U.S.C. 241 note); 24 CFR part 573.

e. Neighborhood Initiatives grants specifically designated in annual HUD appropriations acts (*e.g.,* Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3034 (2009)).

f. Rural Innovation Fund grants as provided for in annual HUD appropriations act(s) (*e.g.,* Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3084 (2009)).

g. Rural Housing and Economic Development grants specifically designated originally in the Fiscal Year 1998 HUD Appropriations Act, Public Law 105–65, 111 Stat. 1344 1997, and subsequent annual HUD appropriations acts.

h. The Renewal Communities (RC) Initiative as authorized under title 26, subtitle A, chapter 1, subchapter X of the Internal Revenue Code, as amended, 26 U.S.C. 1400E *et seq.;* 24 CFR part 599.

i. Urban Development Action Grants under Title I of the Housing and Community Development Act of 1974, Public Law 93–383, 88 Stat. 633 (codified as amended at 42 U.S.C. 5318).

j. The urban Empowerment Zones (EZ), as authorized under title 26, subtitle A, chapter 1, subchapter U of the Internal Revenue Code (codified as amended at 26 U.S.C. 1391 *et seq.*); 24 CFR parts 597 and 598.

k. Youthbuild Program, Title IV, Subtitle D of the Cranston-Gonzalez National Affordable Housing Act, Public Law 101–625, 104 Stat. 4079 (1990) (codified at 42 U.S.C. 12899 *et seq.*) (repealed 2006); 24 CFR part 585.

Further, in the absence of the Deputy Assistant Secretary for Economic Development, the Assistant Secretary redelegates to the Director of the Congressional Grants Division all powers and authorities of the Assistant Secretary necessary to carry out programs and matters listed in Section A.3.

4. Deputy Assistant Secretary for Operations

Except those authorities specifically excluded, the Assistant Secretary redelegates to the Deputy Assistant Secretary for Operations and the Director of Technical Assistance and Management all powers and authorities of the Assistant Secretary necessary to carry out the following Community Planning and Development programs and matters:

a. Technical Assistance and Capacity Building awards authorized under any program or matter delegated to the Assistant Secretary for Community Planning and Development (*e.g.,* section 107 of the Housing and Community Development Act of 1987, as amended and Section 4 Capacity Building for Community Development and Affordable Housing Grants program as authorized by Section 4 of the HUD Demonstration Act of 1993 (Pub. L. 103–120, 107 Stat. 1148, 42 U.S.C. 9816 note), as amended, and as provided for in annual and supplemental HUD appropriations acts (*e.g.,* Consolidated Appropriations Act 2010, Public Law 111–117, 123 Stat. 3093 (2009)).

b. All programs consolidated in the Revolving Fund (Liquidating Programs) established pursuant to Title II of the Independent Offices Appropriations Act, Public Law 98–45, 97 Stat. 223 (1983) (codified at 12 U.S.C. 1701g–5), including all authority of the Assistant Secretary with respect to functions, administration and management of the Revolving Fund (Liquidating Programs).

Only the Assistant Secretary is the responsible official for allotments in the Revolving Fund (Liquidating Programs).

Section B. General Authority Excepted

The authority redelegated under Section A does not include:

1. The authority to issue or waive regulations covered by section 7(q) of the Department of Housing and Urban Development Act;

2. The authority to exercise the Federal Agency waiver authority provided under 49 CFR 24.7;

3. The authority to enter regulations or directives into Departmental clearance; or

4. Any authority not delegated to the Assistant Secretary for Community Planning and Development under the Consolidated Delegation of Authority for Community Planning and Development.

The Assistant Secretary may revoke at any time this redelegation with respect to the programs and matters listed in Section A.

Section C. Authority to Further Redelegate

The authority redelegated in Section A may be further redelegated to employees of the Department.

Section D. Redelegations Superseded

This notice and the notice of redelegation of authority to subordinate employees within CPD Field Offices also published today supersede all prior redelegations of authority from the Assistant Secretary of Community Planning and Development.

Section E. Actions Ratified

The Assistant Secretary hereby ratifies all actions previously taken by the Deputy Assistant Secretaries of Community Planning Development and other specified HUD officials, with respect to the programs and matters listed in Section A.

Authority: Section 7(d), Department of Housing and Urban Development Act, 42 U.S.C. 3535(d).

Dated: October 4, 2011.

Mercedes M. Márquez,

Assistant Secretary for Community Planning and Development.

[FR Doc. 2011–26912 Filed 10–17–11; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

Ocean Energy Safety Advisory Committee (OESC); Notice of Meeting

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE), Interior.

ACTION: Notice of meeting.

SUMMARY: OESC will meet at the Department of the Interior's South Interior Building in Washington, DC.

DATES: Monday, November 7, 2011, from 1 p.m. to 5 p.m. and Tuesday, November 8, 2011, from 8 a.m. to 5 p.m.

ADDRESSES: South Interior Building Auditorium, 1951 Constitution Avenue, NW., Washington, DC 20240.

FOR FURTHER INFORMATION CONTACT: Mr. Joseph R. Levine at the Bureau of Safety and Environmental Enforcement, 381 Elden Street, Herndon, Virginia 20170–4187. He can be reached by telephone at (703) 787–1033 or by electronic mail at *joseph.levine@bsee.gov.*

SUPPLEMENTARY INFORMATION: OESC consists of representatives from industry, Federal Government agencies, non-governmental organizations, and the academic community. It provides policy advice to the Secretary of the Interior through the Director of BSEE on matters relating to ocean energy safety, including, but not limited to drilling and workplace safety, well intervention and containment, and oil spill response.

The agenda for Monday, November 7, will address the progress on OESC outreach to the academic community and the states. The OESC Subcommittees will report on their progress to date on their interim recommendations on oil spill prevention, containment, spill response and safety management systems for the OESC's consideration and action.

The agenda for Tuesday, November 8, will address BSEE's incident data analysis; development and implementation of safety and environmental management systems from the perspective of major and independent operators; a summary of the findings of the Deepwater Horizon Joint Investigation Team; draft American Petroleum Institute (API) standards *Deepwater Well Design and Construction* (API Recommended Practice 96) and *Well Construction Interface Document Guidelines* (API Bulletin 97); and BSEE's proposed rule on revisions to safety and environmental management systems.

The meeting is open to the public. Approximately 90 visitors can be accommodated on a first-come-first-served basis. Please be aware that the South Interior Building is a Federal Government facility and Government issued picture identification must be presented to enter the building. Members of the public will have the opportunity to comment on a first-come-first-served basis during the time allotted for public comment and may submit written comments to the OESC during the meeting or by e-mail to the Committee at *OESC@boemre.gov.*

Minutes of the OESC meeting will be available for public inspection on the Committee's Web site at: *http://www.boemre.gov/mmab/EnergySafety.htm.*

Authority: Federal Advisory Committee Act, Pub. L. No. 92–463, 5 U.S.C. Appendix 1, and the Office of Management and Budget's Circular No. A–63, Revised.

Dated: October 12, 2011.

Michael R. Bromwich,

Director, Bureau of Safety and Environmental Enforcement.

[FR Doc. 2011–26945 Filed 10–17–11; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R8–ES–2011–N178; 80221–1113–0000–C2]

Endangered and Threatened Wildlife and Plants; Draft Revised Recovery Plan, First Revision, for Lost River Sucker and Shortnose Sucker

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of document availability for review and public comment.

SUMMARY: We, the Fish and Wildlife Service, announce the availability of our draft revised recovery plan, first revision, for Lost River sucker and shortnose sucker under the Endangered Species Act of 1973, as amended (Act). These fish species are found in southern Oregon and northern California. We are revising this plan because a substantial amount of new information is available related to recovery of both species, making it appropriate to incorporate new information into the recovery program. We request review and comment from local, State, and Federal agencies and the public. We will also accept any new information on the species' status throughout their ranges.

DATES: We must receive written comments on or before December 19, 2011. However, we will accept information about any species at any time.

ADDRESSES: If you wish to review the draft recovery plan, you may obtain a copy from our Web site at *http://www.fws.gov/endangered/species/recovery-plans.html.* Alternatively, you may contact the Klamath Falls Fish and Wildlife Office, U.S. Fish and Wildlife Service, 1936 California Ave., Klamath Falls, OR 97601; (541–885–8481, phone). If you wish to comment on the plan, you may submit your comments in writing by any one of the following methods:

- *U.S. mail:* Field Supervisor, at the above address;
- *Hand delivery:* Klamath Falls Fish and Wildlife Office at the above address;
- *Fax:* (541) 885–7837; or
- E-mail: *FW8KFFWOESComments@fws.gov.*

For additional information about submitting comments, see ''Request for Public Comments,'' below.

FOR FURTHER INFORMATION CONTACT: Laurie Sada, Field Supervisor, at the above address, phone number, or e-mail.

SUPPLEMENTARY INFORMATION:

Background

Recovery of endangered or threatened animals and plants to the point where they are again secure, self-sustaining members of their ecosystems is a primary goal of our endangered species program under the Act (Act; 16 U.S.C. 1531 *et seq.*). Recovery means improvement of the status of listed species to the point at which listing is no longer appropriate under the criteria set out in section 4(a)(1) of the Act. The Act requires the development of recovery plans for listed species, unless such a plan would not promote the conservation of a particular species.

Species' History

The Lost River sucker (*Deltistes luxatus*) and shortnose sucker (*Chasmistes brevirostris*) are two species of fish that inhabit a limited number of lakes and reservoirs in the upper Klamath Basin, including the Lost River sub-basin, in southern Oregon and northern California. We listed these species as endangered throughout their entire range under the Act on July 18, 1988 (53 FR 27130). We originally completed and announced a recovery plan for the species on March 17, 1993 (USFWS 1993, pp. 1–108). However, a substantial amount of additional information is now available, and it is appropriate to revise the plan and incorporate this new information into the recovery program.

These two species are very similar in ecology. Lost River and shortnose suckers predominantly inhabit lake environments, but also periodically utilize stream/river, marsh, and shoreline habitats. Both species spawn during spring, over gravel bottoms in tributary streams and rivers (Buettner and Scoppettone 1990, pp. 19–20, 44–46). A smaller but significant number of Lost River sucker also spawn over gravel bottoms at shoreline springs along the margins of Upper Klamath Lake (Janney *et al.* 2009, pp. 8–9). Larvae spend relatively little time after hatching in rivers or streams before drifting passively to downstream lakes (Cooperman and Markle 2003, p. 1138). Once in a lake environment, larvae move into relatively shallow vegetated areas along the shoreline. This vegetation provides cover from predators, protection from currents and turbulence, and sources of food (Cooperman and Markle 2004, p. 365). Within 1 to 2 months, larvae become juveniles and begin to utilize nonvegetated and deeper off-shore habitats (Burdick *et al.* 2008, p. 417). Adults occupy open water habitats throughout the year, except during spawning season, when they migrate to spawning areas. Individuals typically become reproductively mature at 5 to 7 years old, and can live for several decades.

The rationales for listing Lost River sucker were similar to those for shortnose sucker, with many of the same threats continuing through the present day, such that both species remain in danger of extinction. Habitat loss, resulting in restricted access to spawning and rearing habitat, severely impaired water quality, and increased rates of mortality resulting from entrainment in water management structures were cited as causes for declines in populations prior to listing (53 FR 27130; July 18, 1988). Although the rate of habitat loss has slowed in recent years and a significant amount of habitat restoration and screening of water diversion structures has occurred, large amounts of historical sucker habitat remain unavailable or significantly altered. In Upper Klamath Lake, extremely poor water quality, which occurs periodically throughout summer, negatively impacts adult survival rates, and although the specific causes are currently unknown, juvenile survival is also low in these populations. The last time a substantial group of juveniles joined the adult populations in Upper Klamath Lake was during the late 1990s (Janney *et al.* 2008, pp. 1820–1823). For both species, the result of these combined factors was abundances of spawning individuals in 2007 in Upper Klamath Lake that were roughly 40 to 70 percent of their 2001 levels. Lastly, entrainment of larvae and small juveniles through diversion structures continues to drain significant numbers of individuals from Upper Klamath Lake into extremely poor habitats, from which return is unlikely. Clear Lake Reservoir has a single spawning tributary, with poor connectivity when reservoir levels are low and limited passage for spawning migrants when flows are low, making these populations very vulnerable to drought. Within Gerber Reservoir, the shortnose sucker population is apparently affected by hybridization with Klamath largescale sucker (*Catostomus snyderi*).

Recovery Plan Goals

The objective of a recovery plan is to provide a framework for the recovery of species so that protection under the Act is no longer necessary. A recovery plan includes scientific information about the species and provides criteria and actions necessary to enable us to be able to downlist or delist the species. Recovery plans help guide our recovery efforts by describing actions we consider necessary for each species' conservation and by estimating time and costs for implementing needed recovery measures.

To achieve its goals, this draft revised recovery plan identifies the following objectives:

1. Restore or enhance spawning and nursery habitat in Upper Klamath Lake and Clear Lake Reservoir systems;

2. Reduce negative impacts of poor water quality;

3. Clarify and reduce the effects of non-native organisms on all life stages;

4. Reduce the loss of individuals to entrainment;

5. Establish a redundancy and resiliency enhancement program;

6. Maintain or increase larval production;

7. Increase juvenile survival and recruitment to spawning populations; and

8. Protect existing and increase the number of recurring, successful spawning populations.

We believe that by achieving these objectives we will be able to promote healthy, stable population demographics.

As these species meet reclassification and recovery criteria, we review each species' status and consider each species for reclassification on or removal from the Federal List of Endangered and Threatened Wildlife and Plants.

Request for Public Comments

Section 4(f) of the Act requires us to provide public notice and an opportunity for public review and comment during recovery plan development. It is also our policy to request peer review of recovery plans (July 1, 1994; 59 FR 34270). In an appendix to the approved recovery plan, we will summarize and respond to the issues raised by the public and peer reviewers. Substantive comments may or may not result in changes to the recovery plan; comments regarding recovery plan implementation will be forwarded as appropriate to Federal or other entities, so that they can be taken into account during the course of implementing recovery actions. Responses to individual commenters will not be provided, but we will provide a summary of how we addressed substantive comments in an appendix to the approved recovery plan.

We invite written comments on the draft revised recovery plan. We specifically seek comments on the following:

- Do you have comments or concerns regarding the proposed recovery criteria?
- Do actions and priorities in the plan's Implementation Schedule reflect a biologically sound conservation approach for Lost River sucker and shortnose sucker recovery?
- Are the proposed monitoring and management actions appropriate and sufficient?
- Are there important recovery actions which have not been included in the plan?

Before we approve the plan, we will consider all comments we receive by the date specified in **DATES**. Methods of submitting comments are in **ADDRESSES**.

Public Availability of Comments

Before including your address, phone number, e-mail address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Comments and materials we receive will be available, by appointment, for public inspection during normal business hours at our office (see **ADDRESSES**).

Authority

We developed our draft recovery plan under the authority of section 4(f) of the Act, 16 U.S.C. 1533(f). We publish this notice under section 4(f) Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Dated: October 11, 2011.

Alexandra Pitts,

Acting Regional Director, Pacific Southwest Region.

[FR Doc. 2011–26798 Filed 10–17–11; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R1–ES–2011–N201; 10120–1113–0000–F5]

Endangered and Threatened Wildlife and Plants; Recovery Permit Application

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), invite the public to comment on the following application for a recovery permit to conduct enhancement of survival activities with endangered species. The Endangered Species Act of 1973, as amended (Act), prohibits activities with endangered species unless a Federal permit allows such activity. The Act also requires that we invite public comment before issuing such permits.

DATES: To ensure consideration, please send your written comments by November 17, 2011.

ADDRESSES: Endangered Species Program Manager, Ecological Services, U.S. Fish and Wildlife Service, Pacific Regional Office, 911 NE 11th Avenue, Portland, OR 97232–4181. Please refer to the permit number for the application when submitting comments.

FOR FURTHER INFORMATION CONTACT: Grant Canterbury, Fish and Wildlife Biologist, at the above address or by telephone (503–231–2071) or fax (503–231–6243).

SUPPLEMENTARY INFORMATION:

Background

The Act (16 U.S.C. 1531 *et seq.*) prohibits activities with endangered and threatened species unless a Federal permit allows such activity. Along with our implementing regulations in the Code of Federal Regulations (CFR) at 50 CFR 17, the Act provides for permits, and requires that we invite public comment before issuing these permits.

A permit granted by us under section 10(a)(1)(A) of the Act authorizes the permittee to conduct activities with U.S. endangered or threatened species for scientific purposes, enhancement of propagation or survival, or interstate commerce. Our regulations implementing section 10(a)(1)(A) for these permits are found at 50 CFR 17.22 for endangered wildlife species, 50 CFR 17.32 for threatened wildlife species, 50 CFR 17.62 for endangered plant species, and 50 CFR 17.72 for threatened plant species.

Application Available for Review and Comment

We invite local, State, and Federal agencies, and the public to comment on the following application. Please refer to the appropriate permit number for the application when submitting comments.

Documents and other information submitted with this application are available for review, subject to the requirements of the Privacy Act (5 U.S.C. 552a) and Freedom of Information Act (5 U.S.C. 552).

Permit Number: TE–003483

Applicant: U.S. Geological Survey, Pacific Island Ecosystem Research Center, Honolulu, Hawaii.

The permittee requests an amendment to an existing permit to take (capture; band; collect blood, ectoparasites, fecal samples, feather samples, and tissue scrapings of lesions; measure, and release) the Maui akepa (*Loxops coccineus ochraceus*), small Kauai thrush (*Myadestes palmeri*), and Kauai creeper (*Oreomystis bairdi*); and take (capture; band; collect blood, ectoparasites, fecal samples, feather samples, and tissue scrapings of lesions; measure, attach radio transmitters, release, and search for and monitor nests) the akiapolaau (*Hemignathus munroi*), Hawaii akepa (*Loxops coccineus coccineus*), and Hawaii creeper (*Oreomystis mana*) in conjunction with monitoring and population studies on the islands of Hawaii and Kauai in the State of Hawaii, for the purpose of enhancing the species' survival.

The existing permit currently covers limited take of the following species:

Palila (*Loxioides bailleui*),

Laysan duck (*Anas laysanensis*),

Hawaiian hoary bat (*Lasiurus cinereus semotus*),

Nene (*Branta sandvicensis*).

The existing permit also currently covers removal and reduction to possession of the following species:

Cyrtandra giffardii (haiwale),

Melicope zahlbruckneri (alani),

Nothocestrum breviflorum (aiea),

Phyllostegia parviflora var. *glabriuscula* (no common name),

Pleomele hawaiiensis (hala pepe), *Portulaca sclerocarpa* (poe), *Sesbania tomentosa* (ohai).

National Environmental Policy Act (NEPA)

In compliance with NEPA (42 U.S.C. 4321 *et seq.*), we have made an initial determination that the proposed activities in this permit are categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement (516 DM 6 Appendix 1, 1.4C(1)).

Public Availability of Comments

All comments and materials we receive in response to this request will be available for public inspection, by appointment, during normal business hours at the address listed in the **ADDRESSES** section of this notice.

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Authority

We provide this notice under section 10 of the Act (16 U.S.C. 1531 *et seq.*)

Dated: October 7, 2011.

Richard R. Hannan,

Acting Regional Director, Pacific Region, U.S. Fish and Wildlife Service.

[FR Doc. 2011–26866 Filed 10–17–11; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R5–R–2011–N156; BAC–4311–K9–S3]

Iroquois National Wildlife Refuge, Genesee County and Orleans County, NY; Final Comprehensive Conservation Plan and Finding of No Significant Impact for Environmental Assessment

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of our final comprehensive conservation plan (CCP) and finding of no significant impact (FONSI) for the environmental assessment (EA) for Iroquois National Wildlife Refuge (NWR, refuge), Genesee County and Orleans County, New York. In this final CCP, we describe how we will manage this refuge for the next 15 years.

ADDRESSES: You may view or obtain copies of the final CCP and FONSI/EA by any of the following methods. You may request a hard copy or CD–ROM.

Agency Web site: Download a copy of the documents at *http://www.fws.gov/northeast/planning/Iroquois/ccphome.html*.

E-mail: northeastplanning@fws.gov. Include ''Iroquois NWR final CCP'' in the subject line of the message.

U.S. Mail: Iroquois NWR, 1101 Casey Road, Basom, NY 14013.

In-Person Viewing or Pickup: Call 585–948–5445 to make an appointment (necessary for view/pickup only) during regular business hours at above address.

FOR FURTHER INFORMATION CONTACT: Thomas Roster, Project Leader, 585–948–5445, or Thomas Bonetti, Planning Team Leader, 413–253–8307 (phone); *tom_bonetti@fws.gov* (e-mail).

SUPPLEMENTARY INFORMATION:

Introduction

With this notice, we finalize the CCP process for Iroquois NWR in Basom, New York. We started this process through a notice in the **Federal Register** (73 FR 10279, February 26, 2008). We released the draft CCP and the EA to the public, announcing and requesting comments in a notice of availability in the **Federal Register** (75 FR 61171, October 4, 2010).

Iroquois NWR was established in 1958 under the Migratory Bird Conservation Act for ''* * * use as an inviolate sanctuary, or for any other management purpose, for migratory birds'' (16 U.S.C. 715d). The refuge consists of more than 10,800 acres within the rural townships of Alabama and Shelby, New York, midway between Buffalo and Rochester. Freshwater marshes and hardwood swamps are bounded by forests, grasslands, and wet meadows. These areas serve the habitat needs of both migratory and resident wildlife, including waterfowl, songbirds, mammals, and amphibians, as well as numerous indigenous plant species.

We announce our decision and the availability of the FONSI for the final CCP for Iroquois NWR in accordance with National Environmental Policy Act (NEPA) (40 CFR 1506.6(b)) requirements. We completed a thorough analysis of impacts on the human environment, which we included in the EA that accompanied the draft CCP. The CCP will guide us in managing and administering Iroquois NWR for the next 15 years.

Background

The National Wildlife Refuge System Administration Act of 1966 (16 U.S.C. 668dd–668ee) (Administration Act), as amended by the National Wildlife Refuge System Improvement Act of 1997, requires us to develop a CCP for each NWR. The purpose for developing a CCP is to provide refuge managers with a 15-year plan for achieving refuge purposes and contributing toward the mission of the National Wildlife Refuge System, consistent with sound principles of fish and wildlife management, conservation, legal mandates, and our policies. In addition to outlining broad management direction on conserving wildlife and their habitats, CCPs identify wildlife-dependent recreational opportunities available to the public, including opportunities for hunting, fishing, wildlife observation and photography, and environmental education and interpretation. We will review and update the CCP at least every 15 years in accordance with the Administration Act.

CCP Alternatives, Including Selected Alternative

Our draft CCP and our EA (75 FR 61171) addressed several issues. To address these, we developed and evaluated the following alternatives.

Alternative A (Current Management): Alternative A continues existing programs and activities and serves as the baseline against which to compare the other alternatives. Under current management, we manage open water and emergent marsh impoundments, early successional habitat including grasslands, shrublands, and forest habitat including a conifer plantation. Under alternative A, we would continue to conduct furbearer management, monitor waterfowl during spring and fall migration, conduct landbird surveys, and manage for invasive species in the same manner as at present. We would maintain existing opportunities for visitors to engage in wildlife observation and photography, and environmental education and interpretation, as well as maintain existing hunting and fishing opportunities on the refuge. We would maintain existing infrastructure and buildings, and maintain current staffing levels.

Alternative B (the Service-preferred alternative): This alternative focuses on enhancing the conservation of wildlife through habitat management, as well as providing additional visitor opportunities on the refuge. Alternative B incorporates existing management

activities and/or provides new initiatives or actions aimed at improving efficiency and progress towards refuge goals and objectives. Some of the major strategies proposed include increasing grassland, shrubland, and forest habitats, replacing non-native conifer plantation with native forest species, restricting public access to designated areas of the refuge year-round, and implementing a permit system for hunting upland game, migratory birds, and big game. This alternative would increase some existing wildlife-dependent recreational activities, including wildlife observation and hunting. We would co-locate the Lower Great Lakes Fish and Wildlife Conservation Office (LGLFWCO) with a new visitor contact station and administrative building by adding on to the existing building. If funds permit, we would expand our existing staff to include a full-time permanent law enforcement officer, maintenance worker, biological technician, and one part-time biological technician.

Alternative C (Improved Biological Integrity): Alternative C prominently features additional management that aims to restore or mimic natural ecosystem processes or function to achieve refuge purposes. Under alternative C, refuge habitat conditions would change as a result of management decisions that target a more natural state and emphasize restoration to historical habitats. Refuge impoundments would no longer be actively managed and some would be removed. This would result in a decrease of 329 acres of open water and emergent marsh habitat. Grassland acres would be reduced by 50 percent as only the two largest grassland units would be managed. Management of shrublands would be discontinued, and the only shrub habitats that would remain are small native shrub swamps. Forest cover would increase (1,548 additional acres) under this alternative in response to the reversion, succession, and conversion of conifer plantations and other refuge habitats to forest. Similar to alternative B, we propose to restrict public access to designated areas of the refuge year-round, allowing wildlife observation, hiking, and walking on established refuge nature trails. Also, we propose to co-locate the LGLFWCO currently located in Amherst, New York, with a new visitor contact station and administration building at Iroquois NWR.

Comments

We solicited comments on the draft CCP and the EA for Iroquois NWR via a **Federal Register** notice that was published on October 4, 2010 (75 FR 61171). We received 37 comments, which we assessed during the content analysis process. Appendix I in the final CCP includes a summary of those comments, our responses to them, and additional rationale for any changes made.

Selected Alternative

We have selected alternative B for implementation, with the following modifications:

- Due to comments directed at closing the refuge to wandering, we decided to allow visitors unrestricted access off designated trails, but only during the hunting season (October 1 to the end of February). All visitors, including those wandering on the refuge, must wear hunter orange during the firearm deer seasons. Hunter orange must be visible from 360 degrees and must be at least 400 square inches of solid fluorescent orange on head, chest, and back. There will be no wandering in any refuge wetlands, only upland wandering will be permitted. The refuge will continue to restrict public access for hiking and walking to designated trails from March 1 to September 30.

- Based on feedback we received from our partners and the public, we decided to modify the alternative B turkey hunting proposal. The new framework will consist of two seasons. The first season will run from May 1 to May 15 with 50 permits available. The second season will run from May 16 to May 31 with 25 permits available. Permits will be allocated on a lottery system basis with hunters choosing their desired season in order of preference. Hunters may receive a permit for one season only.

- The refuge also reconsidered its decision to not allow fall turkey hunting on the refuge. There will be no additional administrative burden on the refuge by having this season added to the refuge hunts.

Public Availability of Documents

In addition to any methods in **ADDRESSES**, you can view or obtain documents on our regional planning Web site: *http://www.fws.gov/northeast/planning/*.

Dated: September 16, 2011.

Theresa E. Rabot,

Acting Regional Director, Northeast Region, U.S. Fish and Wildlife Service, Hadley, Massachusetts.

[FR Doc. 2011–26934 Filed 10–17–11; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

FWS–R1–R–2011–N064; 10137–8555–11RG–8H]

Long Range Transportation Plan for Fish and Wildlife Service Lands in Hawai'i, Idaho, Northern Nevada, Oregon, Washington, and the Pacific Island Territories

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of the final draft Long Range Transportation Plan (LRTP) for Fish and Wildlife Service Lands in Hawai'i, Idaho, Northern Nevada, Oregon, Washington, and the Pacific Island Territories (the Service's Region 1) for public review and comment. The Draft LRTP outlines a strategy for improving and maintaining transportation assets that provide access to Service-managed lands in Region 1 over the next 20 years.

DATES: Please provide your comments by November 17, 2011.

ADDRESSES: The Draft LRTP is available on our *Web site: http://www.fws.gov/pacific/planning/*. We also have a limited number of printed and CD-ROM copies of the Draft LRTP. You may request a copy or submit comments by any of the following methods.

- *E-mail: fw1LRTPComments@fws.gov.*
- *U.S. mail:* Jeff Holm, Regional Transportation Coordinator, U.S. Fish and Wildlife Service, 911 NE 11th Avenue, Portland, OR 97232.
- *Fax:* Attn: Jeff Holm, (503) 231–2364.
- *In-Person Drop-off:* During regular business hours to Jeff Holm, Regional Transportation Coordinator, U.S. Fish and Wildlife Service, 911 NE 11th Avenue, Portland, OR 97232.

FOR FURTHER INFORMATION CONTACT: Jeff Holm, (503) 231–2126.

SUPPLEMENTARY INFORMATION:

Introduction

The Safe, Accountable, Flexible, Efficient, Transportation Equity Act: A Legacy for Users (SAFETEA–LU) of August 10, 2005, (Pub. L. 109–59) requires all Federal land management agencies to conduct long-range transportation planning in a manner that is consistent with metropolitan planning organizations and state departments of transportation planning. With this notice, we make the Draft

LRTP for Region 1 available for public review and comment. We developed the Draft LRTP to achieve the following:

- Establish a defensible structure for transportation planning and decision-making.
- Establish a vision, mission, goals, and objectives for transportation planning.
- Implement coordinated and cooperative transportation partnerships in an effort to improve the Service's transportation infrastructure.
- Comply with SAFETEA–LU.
- Integrate transportation planning and funding for refuges and fish hatcheries into our existing and future management plans and strategies (*e.g.,* comprehensive conservation plans and comprehensive hatchery management plans).
- Increase awareness of alternative transportation systems and associated benefits.
- Develop best management practices for transportation improvements on Service lands.
- Serve as a pilot project for the implementation of a regional transportation planning process within the Service.

Draft LRTP Mission, Goals, and Objectives

The Draft LRTP's mission, goals, and objectives are intended to provide a systematic approach to guide the process for evaluating and selecting transportation improvement projects for lands managed by Region 1. These guiding principles have shaped the development, conclusions, and recommendations of the Draft LRTP.

The mission of the LRTP is to support the Service's mission, by connecting people to fish, wildlife, and their habitats, through strategic implementation of transportation programs. The LRTP has six overall goals: (1) Protecting natural resources; (2) ensuring reliability and safety; (3) welcoming and orienting visitors; (4) integrating with larger Service planning; (5) developing and enhancing partnerships; and (6) adopting and promoting sustainability. Each goal includes distinct objectives that identify how the Service will accomplish each goal. The objectives for each goal follow.

Goal 1: Ensure That the Transportation Program Helps Conserve and Enhance Fish, Wildlife, and Plant Resources and Their Habitats

- *Objective 1:* Identify, research, and adopt best management practices for planning, design, construction, and maintenance of transportation activities and facilities that mitigate or avoid negative impacts.
- *Objective 2:* Reduce transportation-related conflicts within fish and wildlife corridors and habitat on or adjacent to Service lands.

Goal 2: Provide a Safe and Reliable Transportation Network to and Within Service Lands

- *Objective 1:* Identify and reduce safety problems and modal conflicts (*i.e.,* between pedestrians, automobiles, horseback riders, off-road vehicles, maintenance vehicles, *etc.*) to and within Service lands.
- *Objective 2:* Ensure that mission-critical transportation assets are maintained in good condition.

Goal 3: Develop and Maintain a Transportation Network That Welcomes and Orients Visitors

- *Objective 1:* Provide information that enables visitors to easily find and navigate refuge and hatchery sites.
- *Objective 2:* Engage visitors in wildlife conservation and enhance their enjoyment of natural resources by providing compelling information about the National Wildlife Refuge System and Fisheries Program.
- *Objective 3:* Create a consistent and recognizable identity throughout Service units by using standard materials for readily observed physical elements associated with the transportation system.

Goal 4: Integrate Transportation Planning Into Service Plans and Processes

- *Objective 1:* Ensure consistency and coordination between the project, unit, and regional and national levels of planning.
- *Objective 2:* Define need for transportation improvements and prioritize projects using a scientific and objective process.

Goal 5: Develop Partnerships To Leverage Resources and Develop Integrated Transportation Solutions

- *Objective 1:* To the extent authorized by law, pursue opportunities for transportation funding and resources.
- *Objective 2:* Cooperate with public and private sector partners to address shared transportation issues that impact Service goals.

Goal 6: Adopt and Promote Sustainable Transportation Practices

- *Objective 1:* Address climate change and other environmental factors at all levels of transportation planning, design, project delivery, operations, and maintenance.
- *Objective 2:* Reduce the Service's carbon footprint by improving access to and within Service lands by transit and nonmotorized transportation modes, and providing improved visitor information systems.
- *Objective 3:* Reduce fossil fuel energy consumption by staff and visiting public.

Next Steps

After this comment period ends, we will analyze the comments and address them in the form of a final LRTP.

Public Availability of Comments

Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Dated: September 19, 2011.

Richard R. Hannan,

Acting Regional Director, Region 1, Portland, Oregon.

[FR Doc. 2011–26916 Filed 10–17–11; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF JUSTICE

[OMB Number 1125–0004]

Agency Information Collection Activities: Proposed Collection; Comments Requested: Alien's Change of Address Forms: 33/BIA Board of Immigration Appeals and 33/IC Immigration Court

ACTION: 60-Day Notice of Information Collection Under Review.

The Department of Justice (DOJ), Executive Office for Immigration Review (EOIR), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for ''sixty days'' until December 19, 2011. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and

Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to e-mail them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the 8 digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please call Robin M. Stutman, General Counsel, Executive Office for Immigration Review, U.S. Department of Justice, Suite 2600, 5107 Leesburg Pike, Falls Church, Virginia 22041; telephone: (703) 305–0470, or the DOJ Desk Officer at 202–395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of this information collection:

(1) *Type of Information Collection:* Revision of a currently approved collection.

(2) *Title of the Form/Collection:* Alien's Change of Address Forms: 33/BIA Board of Immigration Appeals and 33/IC Immigration Court.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection:* Form Numbers: Form EOIR 33/BIA and 33/IC. Executive Office for Immigration Review, United States Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* An individual appearing before the Immigration Court or the Board of Immigration Appeals. Other: None. Abstract: The information on the change of address form is used by the Immigration Courts and the Board of Immigration Appeals to determine where to send notices of the next administrative action or of any decisions in an alien's case.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 15,000 respondents will complete the form once annually with an average of 5 minutes per response.

(6) *An estimate of the total public burden (in hours) associated with the collection:* There are an estimated 1,245 total burden hours associated with this collection annually.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street, NE., Room 2E–808, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2011–26873 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–30–P

DEPARTMENT OF JUSTICE

Notice of Proposed Consent Decree Pursuant to the Comprehensive Environmental Response, Compensation and Liability Act

Notice is hereby given that on October 4, 2011, a proposed consent decree in *United States et al.* v. *Airgas Carbonic, Inc., et. al.,* Civil Action No. 1:11–cv–163 was lodged with the United States District Court for the Southern District of Georgia.

In this action, filed pursuant to the Comprehensive Environmental Response, Compensation and Liability Act, the United States and the State of Georgia sought (a) The reimbursement of the Federal and state governments' incurred and to be incurred response costs relating to the Alternate Energy Resources, Inc. Site (AER Site), which is located in Augusta, Richmond County, Georgia; and (b) the performance of the remedial design and the remedial action (RD/RA) for the AER Site consistent with the National Contingency Plan, 40 CFR part 300 (as amended).

The parties in this case have reached a proposed settlement. Pursuant to the proposed Consent Decree, seventy-three parties (the Settling Performing Parties), including sixty-eight (68) private parties, four Federal agencies and one state agency, will perform the RD/RA work for the Site at an approximate cost of $7.3 million. The Federal and the state agencies will participate in the clean-up by contributing financially to the private parties who will be performing the RD/RA work. Certain of these Settling Performing Parties have already spent approximately $1.1 million in Site-related investigative and response activities.

Additionally, seven hundred and ninety-seven (797) other parties (*De Minimis* Parties), including private parties, and Federal and state agencies, will also contribute financially to the Settling Performing Parties' performance of the RD/RA work and to the reimbursement of the Federal and state costs incurred and to be incurred.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the Consent Decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, and either e-mailed to *pubcomment-ees.enrd@usdoj.gov* or mailed to P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to the Consent Decree for civil action *United States et al.* v. *Airgas Carbonic, Inc. et al.,* DOJ Ref. No. 90–11–3–10081.

The proposed Consent Decree may be examined at the United States Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, GA 30303. During the public comment period, the Consent Decree may also be examined on the following Department of Justice Web site, *http://www.usdoj.gov/enrd/Consent_Decrees.html.* A copy of the Consent Decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood (*tonia.fleetwood@usdoj.gov*), fax no. (202) 514–0097, phone confirmation number (202) 514–1547. In requesting a copy from the Consent Decree Library, please enclose a check (25 cents per page reproduction cost) in the amount of $29.50 (Consent Decree with exhibits is $122.25; Consent Decree with exhibits and signature pages is $343.75) payable to the U.S. Treasury or, if by e-mail or fax, forward a check in that amount to the Consent Decree Library at the stated address.

Henry S. Friedman,

Assistant Section Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 2011–26831 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF JUSTICE

Notice of Lodging of Proposed Consent Decree Under the Clean Water Act

Notice is hereby given that on October 7, 2011, a proposed Consent Decree in *United States, et al.* v. *the Ryland Group, Inc.,* Civil Action No. 3:11–cv–00499, was lodged with the United States District Court for the Western District of North Carolina.

The proposed Consent Decree in this Clean Water Act enforcement action against the Ryland Group, Inc. (''Ryland'') resolves allegations of stormwater violations, asserted in a complaint filed concurrently with the Consent Decree. The proposed Consent Decree also resolves related state law claims brought by co-plaintiffs, the State of Colorado, the State of Florida Department of Environmental Protection, the State of Illinois, the State of Indiana, the State of Maryland, the State of Nevada, and the Commonwealth of Virginia. In addition to the payment of civil penalties of $625,000.00, the settlement requires Ryland to institute a company-wide management, reporting and training program that goes beyond current regulatory requirements, to improve compliance with stormwater requirements.

The Department of Justice will receive for a period of thirty (30) days from the date of this publication comments relating to the Consent Decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, and either e-mailed to *pubcomment-ees.enrd@usdoj.gov* or mailed to P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611, and should refer to *United States, et al.* v. *the Ryland Group, Inc.,* D.J. Ref. 90–5–1–1–08421.

During the public comment period, the Consent Decree may be examined on the following Department of Justice Web site, *http://www.usdoj.gov/enrd/Consent_Decrees.html.* A copy of the Consent Decree may also be obtained by mail from the Consent Decree Library, P.O. Box 7611, U.S. Department of Justice, Washington, DC 20044–7611 or by faxing or e-mailing a request to Tonia Fleetwood (*tonia.fleetwood@usdoj.gov*), fax no. (202) 514–0097, phone confirmation number (202) 514–1547. If requesting a copy from the Consent Decree Library by mail, please enclose a check in the amount of $43.75 (25 cents per page reproduction cost) payable to the U.S. Treasury or, if requesting by e-mail or fax, forward a check in that amount to the Consent Decree Library at the address given above. In requesting a copy of the Consent Decree exclusive of appendices, please enclose a check in the amount of $18.00 (25 cents per page reproduction cost) payable to the U.S. Treasury.

Karen Dworkin,

Assistant Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 2011–26807 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms, and Explosives

[OMB Number 1140–0087]

Agency Information Collection Activities: Proposed Collection; Comments Requested; eForm 6 Access Request

ACTION: 30-Day Notice.

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms, and Explosives (ATF) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 76, Number 157, page 50496, on August 15, 2011, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until November 17, 2011. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to e-mail them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the 8 digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please call William Majors on 304–616–4589 or the DOJ Desk Officer at 202–395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Summary of Collection

(1) Type of Information Collection: Extension of a currently approved collection.

(2) Title of the Form/Collection: eForm 6 Access Request.

(3) Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number: ATF F 5013.3. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) Affected public who will be asked or required to respond, as well as a brief abstract: Primary: Business or other for-profit. Other: None.

Need for Collection:

Respondents must complete the eForm 6 Access Request form in order to receive a user ID and password to obtain access to ATF's eForm 6 System. The information is used by the Government to verify the identity of the end users prior to issuing passwords.

(5) An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond: There will be an estimated 500 respondents, who will complete the form within approximately 18 minutes.

(6) An estimate of the total burden (in hours) associated with the collection: There are an estimated 150 total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Policy and Planning Staff, Justice Management Division, Two Constitution Square, 145

N Street, NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2011–26842 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–FY–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

[OMB Number 1140–0097]

Agency Information Collection Activities: Proposed Collection; Comments Requested; Supplemental Information on Water Quality Consideration

ACTION: 30-Day Notice of Information Collection.

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 76, Number 157, pages 50496–50497, on August 15, 2011, allowing for a 60 day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until November 17, 2011. This process is conducted in accordance with 5 CFR 1320.10. Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the 8 digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please call Gary Kirchoff on 304–616–4421 or the DOJ Desk Officer at 202–395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Summary of Collection

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Supplemental Information on Water Quality Considerations.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection:* Form Number: ATF F 5000.30. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract:* Primary: Individuals or households. Other: None.

Need for Collection:

The data supplied by the applicant is used by ATF to determine if any environmental impact statement or environmental permit is necessary for the proposed operation.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* There will be an estimated 680 respondents who will complete a 30-minute form.

(6) *An estimate of the total burden (in hours) associated with the collection:* There are an estimated 340 total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Policy and Planning Staff, Justice Management Division, 2 Constitution Square, 145 N Street, NE., Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2011–26843 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–FY–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[OMB Number 1117–0014]

Agency Information Collection Activities: Proposed Collection; Comments Requested: Application for Registration, Application for Registration Renewal, Affidavit for Chain Renewal, Application for Modification of Registration for Online Pharmacies, DEA Forms 224, 224a, 224b, 224c

ACTION: 30-Day Notice of Information Collection Under Review.

The Department of Justice (DOJ), Drug Enforcement Administration (DEA) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** at 76 FR 50498, August 15, 2011, allowing for a 60 day comment period. The purpose of this notice is to allow for an additional 30 days for public comment until November 17, 2011. This process is conducted in accordance with 5 CFR 1320.10.

If you have comments, especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact John W. Partridge, Chief, Liaison and Policy Section, Office of Diversion Control, Drug Enforcement Administration, 8701 Morrissette Drive, Springfield, VA 22152; (202) 307–7297.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to e-mail them to *oira_submission@omb.eop.gov* or fax them to (202) 395–7285. All comments should reference the eight-digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please contact John W. Partridge, Chief, Liaison and Policy Section, Office of Diversion Control, Drug Enforcement Administration, 8701 Morrissette Drive, Springfield, VA 22152, (202) 307–7297, or the DOJ Desk Officer at (202) 395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of Information Collection 1117–0014

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Application for Registration; Application for Registration Renewal; Affidavit for Chain Renewal; Application for Modification of Registration for Online Pharmacies.

(3) *Agency form number, if any, and the applicable component of the Department sponsoring the collection:*

Form number: DEA Forms 224, 224a, 224b, 224c.

Component: Office of Diversion Control, Drug Enforcement Administration, U.S. Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract:*

Primary: Business or other for-profit.

Other: Not-for-profit institutions; State, local, or tribal government.

Abstract: All firms and individuals who dispense controlled substances must register with the DEA under the Controlled Substances Act. Pharmacies wishing to be online pharmacies must apply to modify their registrations. Such registration is mandatory under the law and needed for control measures over legal handlers of controlled substances and to monitor their activities.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:*

	Number of annual respondents	Average time per response	Total annual hours
DEA–224 (paper)	5,465	0.2 hours (12 minutes)	1,093
DEA–224 (electronic)	75,342	0.13 hours (8 minutes)	10,045.6
DEA–224a (paper)	66,006	0.2 hours (12 minutes)	13,201.2
DEA–224a (electronic)	311,300	0.07 hours (4 minutes)	20,753.333
DEA–224b (chain renewal)*	23	5 hours	115
DEA–224c	0	0.25 hours (15 minutes)	0
Total	458,136		45,208.13

*In total, 68 chain pharmacies represent 36,490 individual pharmacy registrants. Pharmacies register for a three-year registration period. In calendar year 2010, the year for which estimates are calculated, 23 chains registered 22,780 individual pharmacies.

(6) *An estimate of the total public burden (in hours) associated with the collection:* It is estimated that there are 45,208 annual burden hours associated with this information collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, 145 N Street, NE., Suite 2E–502, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, U.S. Department of Justice.

[FR Doc. 2011–26875 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[OMB Number 1117–0012]

Agency Information Collection Activities: Proposed Collection; Comments Requested: Application for Registration, Application for Registration Renewal, Affidavit for Chain Renewal—DEA Forms 225, 225a, 225b

ACTION: 60-Day Notice of Information Collection Under Review.

The Department of Justice (DOJ), Drug Enforcement Administration (DEA), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted until December 19, 2011. This process is conducted in accordance with 5 CFR 1320.10.

If you have comments, especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact John W. Partridge, Chief, Liaison and Policy Section, Office of Diversion Control, Drug Enforcement Administration, 8701 Morrissette Drive, Springfield, VA 22152; (202) 307–7297.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information,

including the validity of the methodology and assumptions used;

• Enhance the quality, utility, and clarity of the information to be collected; and

• Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Overview of Information Collection 1117–0012

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Application for Registration, Application for Registration Renewal, Affidavit for Chain Renewal.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number:* DEA Forms 225, 225a, 225b. Component: Office of Diversion Control, Drug Enforcement Administration, Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract:*

Primary: Business or other for-profit.

Other: Not-for-profit institutions; State, local, and Tribal governments.

Abstract: The Controlled Substances Act requires all persons that manufacture, distribute, import, export, analytical laboratories, or conducts research with controlled substances to register with DEA. Registration provides a closed system of distribution to control the flow of controlled substances through the distribution chain.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* DEA Form 225 is submitted on an as-needed basis by persons seeking to become registered, DEA Form 225a is submitted on an annual basis thereafter to renew existing registrations, and DEA Form 225b is submitted annually for renewals of chain registrants.

	Number of annual respondents	Average time per response	Total annual hours
DEA–225 (paper)	465	0.5 hours (30 minutes)	232.5
DEA–225 (electronic)	1,562	0.17 hours (10 minutes)	260.33
DEA–225a (paper)	1,345	0.5 hours (30 minutes)	672.5
DEA–225a (electronic)	9,721	0.17 hours (10 minutes)	1,620.17
DEA–225b (chain renewal)*	4	1 hour	4
Total	13,097		2,789.5

* In total, 4 chains represent 85 individual registrant locations.

(6) *An estimate of the total public burden (in hours) associated with the collection:* It is estimated that there are 2,789.5 annual burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Two Constitution Square, 145 N Street, NE., Suite 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, U.S. Department of Justice.

[FR Doc. 2011–26874 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

Office of Justice Programs

[OMB Number 1121–NEW]

Agency Information Collection Activities: Proposed Collection; Comments Requested

ACTION: 30-Day Notice of Information Collection Under Review: Office for Victims of Crime Trafficking Information Management System (TIMS).

The Department of Justice, Office of Justice Programs, Office for Victims of Crime, will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995. The proposed information collection was previously published in the **Federal Register** Volume 76, Number 157, page 50499, on August 15, 2011, allowing for a 60-day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until November 17, 2011. This process is conducted in accordance with 5 CFR 1320.10.

Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: DOJ Desk Officer. The best way to ensure your comments are received is to email them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the 8 digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please contact Pamela Leupen, at 202–307–0711 or the DOJ Desk Officer at 202–395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

(1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency/component, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agencies/components estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of this information collection:

(1) *Type of Information Collection:* New collection.

(2) *Title of the Form/Collection:* OVC Trafficking Information Management System (TIMS) Online.

(3) *The Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection:* Form Number(s): NA. Office for Victims of Crime, Office of Justice Programs, Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract.* Primary: OVC Services to Victims of Human Trafficking Grant recipients (OVC Grantees) Abstract: The OVC Trafficking Information Management System (TIMS) Online is a Web-based database and reporting system, designed to simplify performance reporting required by the OVC Services to Victims of Human Trafficking Grant Initiative. Once approved, OVC will require OVC Grantees to use this electronic tool to submit grant performance data, including demographics about human trafficking victims. OVC intends to publish an annual analysis of these data to provide the crime victims' field with stronger evidence for practices and programs.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond/reply:* There are approximately 30–38 OVC Services to Victims of Human Trafficking Grantees per six-month reporting period. On average, it should take each grantee one hour to seven hours, depending on client case load per reporting period, to enter information into TIMS Online. There are two reporting periods per year.

(6) *An estimate of the total public burden (in hours) associated with the collection:* There is no public burden associated with the collection. This system only pertains to OVC grantees.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Planning and Policy Staff, Justice Management Division, Two Constitution Square, 145 N Street, NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, United States Department of Justice.

[FR Doc. 2011–26877 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–18–P

DEPARTMENT OF JUSTICE

National Institute of Justice

[OMB Number 1121–NEW]

Agency Information Collection Activities: Proposed Collection; Comments Requested: Survey of the Interoperability of Automated Fingerprint Identification Systems Regarding Latent Fingerprint Exchange

ACTION: 30-Day Notice of Information Collection Under Review.

The Department of Justice (DOJ), National Institute of Justice (NIJ), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. This proposed information collection was previously published in the **Federal Register** Volume 76, Number 148, Page 46328, on August 2, 2011, allowing for a 60 day comment period.

The purpose of this notice is to allow for an additional 30 days for public comment until November 17, 2011. This process is conducted in accordance with 5 CFR 1320.10. Written comments concerning this information collection should be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, *Attn:* DOJ Desk Officer. The best way to ensure your comments are received is to e-mail them to *oira_submission@omb.eop.gov* or fax them to 202–395–7285. All comments should reference the 8 digit OMB number for the collection or the title of the collection. If you have questions concerning the collection, please call Mark E. Greene at 202–307–3384 or the DOJ Desk Officer at 202–395–3176.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

—Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

—Enhance the quality, utility, and clarity of the information to be collected; and

—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Overview of this information collection:

(1) *Type of Information Collection:* Establishment survey and initial approval of collection.

(2) *Title of Form/Collection:* Latent Fingerprint Interoperability Survey.

(3) *Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection:* Form Number: none. National Institute of Justice, Office of Justice Programs, Department of Justice.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract:* Primary: State and Local law enforcement agencies with Automated Fingerprint Identification Systems (AFIS). The proposed collection is the only effort that provides an ability to establish the level of interoperability of automated fingerprint identification systems maintained by State and Local law enforcement agencies regarding the electronic exchange of latent fingerprints to support criminal investigations. This collection will enable NIJ; Federal, State, Local, and Tribal law enforcement and government administrators; legislators; and researchers; to understand the technology and policy barriers to local, regional, and national interoperability from the perspective of State and Local criminal investigations requiring the exchange of latent fingerprints across jurisdictional boundaries. Information collected in the core survey and survey addenda will provide critical data on the types and functionalities of fielded AFIS systems in State and Local agencies; the current policy agreements among jurisdictions to permit the sharing, exchange, and searching of latent fingerprints electronically; and the technology-related and policy-related impediments regarding the electronic sharing, exchange, and searching of latent fingerprints across various jurisdictions at the State and Local levels.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 350 to 400 respondents will complete the core

survey and one of two relevant addenda depending on whether the respondent is from a State or Local agency in approximately 60 minutes.

(6) *An estimate of the total public burden (in hours) associated with the collection:* There are an estimated 21,000 to 24,000 total burden hours associated with this collection.

If additional information is required contact: Jerri Murray, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street, NE., Room 2E–508, Washington, DC 20530.

Jerri Murray,

Department Clearance Officer, PRA, U.S. Department of Justice.

[FR Doc. 2011–26876 Filed 10–17–11; 8:45 am]

BILLING CODE 4410–18–P

DEPARTMENT OF LABOR

Mine Safety and Health Administration

Petitions for Modification of Application of Existing Mandatory Safety Standards

AGENCY: Mine Safety and Health Administration, Labor.

ACTION: Notice.

SUMMARY: Section 101(c) of the Federal Mine Safety and Health Act of 1977 and 30 CFR part 44 govern the application, processing, and disposition of petitions for modification. This notice is a summary of petitions for modification submitted to the Mine Safety and Health Administration (MSHA) by the parties listed below to modify the application of existing mandatory safety standards codified in Title 30 of the Code of Federal Regulations.

DATES: All comments on the petitions must be received by the Office of Standards, Regulations and Variances on or before November 17, 2011.

ADDRESSES: You may submit your comments, identified by ''docket number'' on the subject line, by any of the following methods:

1. *Electronic Mail: zzMSHA-comments@dol.gov.* Include the docket number of the petition in the subject line of the message.

2. *Facsimile:* 202–693–9441.

3. *Regular Mail:* MSHA, Office of Standards, Regulations and Variances, 1100 Wilson Boulevard, Room 2350, Arlington, Virginia 22209–3939, Attention: Roslyn B. Fontaine, Acting Director, Office of Standards, Regulations and Variances.

4. *Hand-Delivery or Courier:* MSHA, Office of Standards, Regulations and Variances, 1100 Wilson Boulevard, Room 2350, Arlington, Virginia 22209–3939, Attention: Roslyn B. Fontaine, Acting Director, Office of Standards, Regulations and Variances.

MSHA will consider only comments postmarked by the U.S. Postal Service or proof of delivery from another delivery service such as UPS or Federal Express on or before the deadline for comments. Individuals who submit comments by hand-delivery are required to check in at the receptionist's desk on the 21st floor.

Individuals may inspect copies of the petitions and comments during normal business hours at the address listed above.

FOR FURTHER INFORMATION CONTACT: Barbara Barron, Office of Standards, Regulations and Variances at 202–693–9447 (Voice), *barron.barbara@dol.gov* (E-mail), or 202–693–9441 (Facsimile). [These are not toll-free numbers.]

SUPPLEMENTARY INFORMATION:

I. Background

Section 101(c) of the Federal Mine Safety and Health Act of 1977 (Mine Act) allows the mine operator or representative of miners to file a petition to modify the application of any mandatory safety standard to a coal or other mine if the Secretary determines that:

(1) An alternative method of achieving the result of such standard exists which will at all times guarantee no less than the same measure of protection afforded the miners of such mine by such standard; or

(2) That the application of such standard to such mine will result in a diminution of safety to the miners in such mine. In addition, the regulations at 30 CFR 44.10 and 44.11 establish the requirements and procedures for filing petitions for modification.

II. Petitions for Modification

Docket Number: M–2011–031–C.

Petitioner: Chief Mining, Inc., P.O. Box 446, Glen Daniel, West Virginia 25844.

Mine: Jim's Branch No. 2 Mine, MSHA Mine I.D. No. 46–08577, located in Wyoming County, West Virginia.

Regulation Affected: 30 CFR 75.1101–1(b) (Deluge-type water spray system).

Modification Request: The petitioner requests a modification of the existing standard to eliminate the use of blow-off dust covers for the spray nozzles of a deluge-type water spray system. The petitioner states that:

(1) Frequent inspections and functional testing of the system are conducted.

(2) Dust covers are not necessary because the nozzles can be maintained in an unclogged condition through weekly use.

(3) It is burdensome to recap the large number of covers on a weekly basis after each inspection and functional test.

As an alternative to using the blow-off dust covers, the petitioner proposes to:

(1) Conduct a weekly inspection and functional test of the complete deluge-type water spray system; and

(2) Record the result of the examination and functional test and record any malfunction or clogged nozzle detected in a book maintained on the surface. The record will be retained at the mine for one year.

The petitioner asserts that the alternative method will at all times guarantee no less than the same measure of protection afforded the miners at Jim's Branch No. 2 Mine by the existing standard.

Docket Number: M–2011–032–C.

Petitioner: Frontier Coal Company, Inc., 100 Cranberry Creek Drive, Beckley, West Virginia 25801.

Mine: Double Camp No. 1 Mine, MSHA I.D. No. 46–09227, located in Wyoming County, West Virginia.

Regulation Affected: 30 CFR 75.1101–1(b) (Deluge-type water spray system).

Modification Request: The petitioner requests a modification of the existing standard to eliminate the use of blow-off dust covers for the spray nozzles of a deluge-type water spray system. The petitioner states that:

(1) Frequent inspections and functional testing of the system are conducted.

(2) Dust covers are not necessary because the nozzles can be maintained in an unclogged condition through weekly use.

(3) It is burdensome to recap the large number of covers on a weekly basis after each inspection and functional test.

As an alternative to using the blow-off dust covers, the petitioner proposes to:

(1) Conduct a weekly inspection and functional test of the complete deluge-type water spray system; and

(2) Record the result of the examination and functional test and record any malfunction or clogged nozzle detected in a book maintained on the surface. The record will be retained at the mine for one year.

The petitioner asserts that the alternative method will at all times guarantee no less than the same measure of protection afforded the miners at Double Camp No. 1 Mine by the existing standard.

Docket Number: M–2011–033–C.

Petitioner: ACI Tygart Complex, 1200 Tygart Drive, Grafton, West Virginia 26354.

Mine: Tygart #1 Mine, MSHA I.D. No. 46–09192, located in Taylor County, West Virginia.

Regulation Affected: 30 CFR 75.503 (Permissible electric face equipment; maintenance) and 30 CFR 18.35 (Portable trailing cables and cords).

Modification Request: The petitioner requests a modification of the existing standard to permit the maximum length of the 995-volt, three-phase alternating current portable (trailing) cable to exceed 500 feet but not to exceed 1,000 feet in length. The trailing cable will have a 90 degree Celsius insulation rating. The petitioner also requests that the maximum length of the 600-volt, three-phase alternating current trailing cables supplying section ventilation fans, loading machines, roof bolters, and shuttle cars be permitted to exceed 500 feet but not exceed 1,000 feet in length and the trailing cable will have a 90 degree Celsius insulation rating. The petitioner states that:

(1) The trailing cable will not be smaller than No. 2 American Wire Gauge (AWG) for the continuous mining machine, the section ventilation fans, roof bolting machines, and shuttlecars.

(2) All circuit breakers used to protect No. 2/0 AWG cables that exceed 850 feet in length will have instantaneous trip units set to trip at 1,500 amperes. The trip settings of these circuit breakers will be sealed and will have permanent, legible labels. The label will identify the circuit as being suitable for protecting No. 2/0 AWG cables.

(3) Replacement circuit breakers and/or instantaneous trip units used to protect No. 2/0 AWG trailing cables will be set to trip at 1,500 amperes and this setting will be sealed.

(4) All circuit breakers used to protect No. 2 AWG trailing cables exceeding 700 feet in length will have instantaneous trip units set to trip at 800 amperes. The trip setting of these circuit breakers will be sealed and will have permanent, legible labels. The labels will identify the circuit breakers as being set for the size of the cable.

(5) Replacement circuit breakers and/or instantaneous trip units used to protect No. 2 AWG cables will be set to trip at 800 amperes and this unit will be sealed.

(6) During each production day, persons designated by the operator will visually examine the trailing cables to ensure that the cables are in safe operating condition and instantaneous settings are sealed and do not exceed the settings stipulated in this petition.

(7) Any trailing cable that is not in safe operating condition will be removed from service immediately and repaired or replaced.

(8) Each splice or repair in the trailing cable will be made according to the manufacturer's instructions for the splice or repair kit. The outer jacket of each splice or repair will be vulcanized with flame-resistant material or made with material accepted by MSHA as flame resistant.

(9) If mining methods or operation procedures cause or contribute to damage of any trailing cable, the cable will be removed from service immediately, repaired or replaced, and additional precautions will be taken to ensure that in the future the cable is protected and maintained in safe operating condition.

(10) Permanent warning labels will be installed and maintained on the covers of each circuit breaker and the trailing cable disconnecting device(s) indicating that the trailing cable can only be connected to a properly adjusted and sealed circuit breaker. The labels will warn miners not to change or alter the sealed short-circuit settings, and not to connect the trailing cables to an improperly adjusted circuit breaker.

(11) The alternative method will not be implemented until all miners designated to examine the integrity of the seals, verify the short-circuit settings, and examine the trailing cable for defects have received training.

(12) Within 60 days after the proposed decision and order becomes final, proposed revisions for the petitioner's approved 30 CFR Part 48 training plan will be submitted to the District Manager. The revisions will specify task training for miners designated to verify that the short-circuit settings of the circuit interrupting device(s) that protect the affected trailing cables do not exceed the specified settings. The training plan will include:

(a) The hazards of setting the short-circuit interrupting device(s) too high to adequately protect the trailing cable.

(b) How to verify that the circuit interrupting device(s) protecting the trailing cable(s) are properly set and maintained.

(c) Mining methods and operating procedures that will protect the trailing cable(s) against damage.

(d) Proper procedures for examining the affected trailing cables to ensure that the cables are in safe operating condition.

The petitioner asserts that the proposed alternative method will at all times guarantee no less than the same measure of protection to all miners at the Tygart #1 Mine as would be provided by the existing standard.

Docket Number: M–2011–008–M.

Petitioner: Intrepid Potash-New Mexico, LLC, P.O. Box 101, Carlsbad, New Mexico 88221.

Mines: Intrepid Potash East Mine, MSHA I.D. No. 29–00170 and Intrepid Potash West Mine, MSHA I.D. No. 29–00175, located in Eddy County, New Mexico.

Regulation Affected: 30 CFR 57.11052 (Refuge areas).

Modification Request: The petitioner requests a modification of the existing standard to permit the use of compressed air or oxygen in canisters, cylinders, or bottles in lieu of compressed air lines and the use of sealed bottled water supply in lieu of waterlines in the mines. The petitioner states that:

(1) The intent of the standard is to ensure that miners in refuge areas are provided with adequate air and water in the event of an emergency.

(2) The proposed modification will provide an equal degree of safety in that the supply of oxygen and drinking water would be provided by the alternative method.

(3) The reliability of the source of air and water would be enhanced by making the refuge area self-contained.

(4) The source of water and air would not be dependent on the installation of external airlines or waterlines that would be susceptible to mechanical damage or restriction.

(5) Permitting the use of compressed air (oxygen) and water improves the portability of the refuge area, allowing the flexibility of installing refuge areas in close proximity to the working areas in the mine. Under the proposed modification the petitioner proposes to undertake the following:

(a) Supply each refuge area with oxygen and water sufficient for the number of miners for which the refuge area is designed.

(b) Provide training on the refuge area guidelines and instructions for affected personnel at least semi-annually.

(6) In addition, the petitioner proposes to provide commercially purchased bottled water in sealed bottles. Sufficient water will be provided in each refuge area, consisting of 2.5 quarts of water for each person per day for at least 5 days (50 person capacity requires 28-gal/day or a total capacity of 140 gallons). A fresh supply of water will be provided not to exceed 2 years.

(a) A supply of packaged disposable drinking cups (at least 5 cups per person) will be maintained in the refuge area.

(b) The condition and quantity of stored water will be confirmed by inspection on a monthly basis, and written instructions for conservation of water will be provided with the refuge supplies.

(7) For compressed oxygen, the petitioner proposes to supply only medical or airline quality oxygen in refuge areas. A supply of not less than 550 liters of oxygen per day per person for a minimum of 5 days will be provided.

(a) Oxygen cylinders will be stored in a safe manner and in compliance with 30 CFR 57.16005 and 57.16006, and away from flammable and combustible materials. A system of regulating the flow of oxygen and monitoring the reserve available will be provided with the refuge area supplies.

(b) Equipment designed for monitoring the oxygen and carbon dioxide level of the ambient air in the refuge area will be provided with the refuge area supplies.

(c) A purge valve will be installed or provided for rapid installation. The condition of the cylinders will be inspected and pressure tested on a monthly basis.

(d) Sufficient carbon dioxide absorbent material will be provided to maintain a carbon dioxide level below 2.0 percent for the duration and number of miners for which the refuge area is designed.

(e) Written instructions for monitoring and maintaining gas levels within the refuge area will be provided with the refuge supplies.

The petitioner asserts that implementation of the proposed modification will enhance the safety of the miners under emergency conditions and mitigate inherent safety issues with regard to the terms of the existing standard and the proposed alternative method will at all times guarantee no less than the same measure of protection afforded by the existing standard.

Docket Number: M–2011–009–M.

Petitioner: Celite Corporation, 2500 Miguelito Road, Lompoc, California 93436.

Mine: Lompoc Plant, MSHA I.D. No. 04–02848, located in Santa Barbara County, California.

Regulation Affected: 30 CFR 56.20001 (Intoxicating beverages and narcotics).

Modification Request: The petitioner requests a modification of the existing standard to permit alcohol slow-fermented from starch, bearing an alcohol content of less than 10 percent alcohol by volume, commonly called ''beer'', to be used at the Lompoc Plant for use in chemical testing that is part of product quality control and research.

The Lompoc Mine is a surface diatomaceous earth mine and processing facility. One of the commercial applications of the finished diatomaceous earth products is as a filtration agent utilized during the brewing process for beer. The finished diatomaceous earth products are integrated onto a fine mesh screen, with other ingredients, thereby creating a ''filter-cake.'' At the end of the brewing process, following fermentation, which results in the creation of the alcohol-containing liquid that is called ''beer,'' the beer is passed-through the filter-cake to remove undesirable contaminants. This results in higher clarity of the beer, which is commercially desirable.

Although diatomaceous earth can be an excellent filtration aid in the production of beer, it also contains naturally-occurring iron, which is undesirable in beer production. If the beer absorbs too much iron, the beer will develop a bitter taste, which is not commercially desirable. Soluble iron in beer also has a deleterious effect on beer stability, which is also not commercially desirable. Accordingly, one of the most critical properties of the diatomaceous earth products is its beer-soluble iron (''BSI'') content.

To ensure that the diatomaceous earth products meet the BSI and other applicable specifications, Celite must engage in testing on-site at the Lompoc Plant to identify the BSI content of the diatomaceous earth products as they are processed. The petitioner proposes to:

(1) Store containers of beer at the Lompoc Plant in secure locations with restricted access;

(2) Use the beer for purposes of quality control testing, statistical method control testing, and research testing; and

(3) Store open containers of beer that may be used during more than one testing event at the Lompoc Plant in secure locations with restricted access.

The petitioner states that the consumption of any intoxicating beverages and narcotics (including beer) will be prohibited, and persons under the influence of alcohol or narcotics will not be permitted on site.

The petitioner asserts that modification of the standard will further the goals of the Mine Act by providing an equivalent level of protection for miners as is provided by the existing standard, and will allow Celite to maintain the commercial viability of the products that are mined at the Lompoc Plant.

Dated: October 12, 2011.

Patricia W. Silvey,

Certifying Officer.

[FR Doc. 2011–26852 Filed 10–17–11; 8:45 am]

BILLING CODE 4510–43–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice (11–097)]

NASA Advisory Council; Information Technology Infrastructure Committee; Meeting

AGENCY: National Aeronautics and Space Administration.

ACTION: Notice of Meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, Public Law 92–463, as amended, the National Aeronautics and Space Administration announce a meeting for the Information Technology Infrastructure Committee of the NASA Advisory Council.

DATES: Tuesday, November 1, 2011, 8:30 a.m.–12 p.m., Local Time.

Meet-Me-Number: 1–877–906–3018, #5343670.

ADDRESSES: NASA Goddard Space Flight Center, 8800 Greenbelt Road, Building 34, Room W305, Greenbelt, MD 20771. (Note that visitors will first need to go to the GSFC Main Gate to gain access).

FOR FURTHER INFORMATION CONTACT: Ms. Karen Harper, Executive Secretary for the Information Technology Infrastructure Committee, National Aeronautics and Space Administration Headquarters, Washington, DC 20546, (202) 358–1807.

SUPPLEMENTARY INFORMATION: The topics of discussion for the meeting are the following:

- NASA IT Summit.
- Goddard Technologies.

The meeting will be open to the public up to the seating capacity of the room. This meeting is also available telephonically by dialing the Meet-Me-Number 1–877–906–3018, #5343670. Visitors will need to show a valid picture identification such as a driver's license to enter into the NASA Goddard Space Flight Center, and must state that they are attending the NASA Advisory Council, Information Technology Infrastructure Committee meeting in Building 34, Room W305. All U.S. citizens desiring to attend the Information Technology Infrastructure Committee at the Goddard Space Flight Center (GSFC) must provide their full name, company affiliation (if applicable), to the GSFC Protective

Services Division no later than the close of business on October 28, 2011. All non-U.S. citizens must submit their name, current address, citizenship, company affiliation (if applicable) to include address, telephone number, and their title, place of birth, date of birth, U.S. visa information to include type, number, and expiration date, U.S. Social Security Number (if applicable), Permanent Resident Alien card number and expiration date (if applicable), place and date of entry into the U.S., and Passport information to include Country of issue, number, and expiration date to the GSFC Security Office no later than the close of business on October 19, 2011. If the above information is not received by the noted dates, attendees should expect a minimum delay of two (2) hours. All visitors to this meeting will report to the Main Gate where they will be processed through security prior to entering GSFC. Please provide the appropriate data, via fax 301–286–1230, noting at the top of the page ''Public Admission to the NASA Advisory Council, Information Technology Infrastructure Committee Meeting at GSFC''. For security questions, please call Pam Starling at 301–286–6865 or *pamela.a.starling@nasa.gov* or Alternate: Debbie Brasel at 301–286–6876 order *deborah.a.brasel@nasa.gov.*

Dated: October 13, 2011.

P. Diane Rausch,

Advisory Committee Management Officer, National Aeronautics and Space Administration.

[FR Doc. 2011–26961 Filed 10–17–11; 8:45 am]

BILLING CODE P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice 11–098]

NASA Advisory Council; Science Committee; Planetary Science Subcommittee; Meeting

AGENCY: National Aeronautics and Space Administration.

ACTION: Notice of meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, Public Law 92–463, as amended, the National Aeronautics and Space Administration (NASA) announces a meeting of the Planetary Science Subcommittee of the NASA Advisory Council (NAC). This Subcommittee reports to the Science Committee of the NAC. The meeting will be held for the purpose of soliciting, from the scientific community and other persons scientific, and technical information relevant to program planning.

DATES: Wednesday, November 2, 2011, 8:30 a.m. to 5 p.m., and Thursday, November 3, 2011, 8:30 a.m. to 4 p.m., Local Time.

ADDRESSES: NASA Headquarters, 300 E Street, SW., Room 6H46, Washington, DC 20546.

FOR FURTHER INFORMATION CONTACT: Ms. Marian Norris, Science Mission Directorate, NASA Headquarters, Washington, DC 20546, (202) 358–4452, fax (202) 358–4118, or *mnorris@nasa.gov.*

SUPPLEMENTARY INFORMATION: The meeting will be open to the public up to the capacity of the room. This meeting is also available telephonically and by WebEx. Any interested person may call the USA toll free conference call number 888–324–3907, pass code PSS, to participate in this meeting by telephone. The WebEx link is *https://nasa.webex.com,* meeting number on November 2 is 991 967 440, and password *PSS@Nov*2; the meeting number on November 3 is 996 034 764, and password *PSS@Nov3.* The agenda for the meeting includes the following topics:

—Status of Impacts on the Planetary Science Division
—Status of Joint NASA–European Space Agency Mars Program
—Europa Jupiter System Mission Descope Options
—Status of European Space Agency JUpitor ICy moon Explorer Potential Mission
—Status of Planetary Research and Analysis Program
—Status of Planetary Science Subcommittee ''Assessment'' Report and Recommendations to Planetary Science Division
—Assessment Group Reports

It is imperative that the meeting be held on these dates to accommodate the scheduling priorities of the key participants. Attendees will be requested to sign a register and to comply with NASA security requirements, including the presentation of a valid picture ID, before receiving an access badge. Foreign nationals attending this meeting will be required to provide a copy of their passport, visa, or green card in addition to providing the following information no less than 10 working days prior to the meeting: full name; gender; date/place of birth; citizenship; visa/green card information (number, type, expiration date); passport information (number, country, expiration date); employer/affiliation information (name of institution, address, country, telephone); title/position of attendee. To expedite admittance, attendees with U.S. citizenship can provide identifying information 3 working days in advance by contacting Marian Norris via e-mail at *mnorris@nasa.gov* or by telephone at (202) 358–4452.

October 13, 2011.

P. Diane Rausch,

Advisory Committee Management Officer, National Aeronautics and Space Administration and Space Administration.

[FR Doc. 2011–27060 Filed 10–17–11; 8:45 am]

BILLING CODE 7510–13–P

NATIONAL LABOR RELATIONS BOARD

Appointments of Individuals to Serve as Members of Performance Review Boards

5 U.S.C. 4314 (c) (4) requires that the appointments of individuals to serve as members of performance review boards be published in the **Federal Register**. Therefore, in compliance with this requirement, notice is hereby given that the individuals whose names and position titles appear below have been appointed to serve as members of performance review boards in the National Labor Relations Board for the rating year beginning October 1, 2010 and ending September 30, 2011.

Name and Title

William B. Cowen—Solicitor

Kathleen A. Nixon—Deputy Chief Counsel to the Chairman

Gary W. Shinners—Deputy Executive Secretary

Robert Schiff—Executive Assistant to the Chairman

Barry J. Kearney—Associate General Counsel, Division of Advice

Anne G. Purcell—Associate General Counsel, Division of Operations Management

Gloria Joseph—Director of Administration, Division of Administration

John H. Ferguson—Associate General Counsel, Division of Enforcement Litigation

Dated: Washington, DC, October 13, 2011.

By Direction of the Board.

Gary W. Shinners,

Deputy Executive Secretary.

[FR Doc. 2011–26951 Filed 10–17–11; 8:45 am]

BILLING CODE 7545–01–P

NATIONAL SCIENCE FOUNDATION

Advisory Committee for Polar Programs; Notice of Meeting

In accordance with Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Advisory Committee for Polar Programs (1130).

Date/Time: November 14, 2011, 8:30 a.m. to 5:30 p.m.; November 15, 2011, 8:30 a.m. to 2 p.m.

Place: National Science Foundation, 4201 Wilson Boulevard, Room 1235, Arlington, VA.

Type of Meeting: Open.

Contact Person: Dr. Kelly Falkner, Office of Polar Programs (OPP). National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230. (703) 292–8030.

Minutes: May be obtained from the contact person listed above.

Purpose of Meeting: To advise NSF on the impact of its policies, programs, and activities on the polar research community, to provide advice to the Director of OPP on issues related to long-range planning.

Agenda: Staff presentations and discussion on opportunities and challenges for polar research, education and infrastructure; discussion of OPP Strategic Vision.

Dated: October 12, 2011.

Susanne Bolton,

Committee Management Officer.

[FR Doc. 2011–26850 Filed 10–17–11; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2011–0241]

Biweekly Notice; Applications and Amendments to Facility Operating Licenses; Involving No Significant Hazards Considerations

Background

Pursuant to section 189a. (2) of the Atomic Energy Act of 1954, as amended (the Act), the U.S. Nuclear Regulatory Commission (the Commission or NRC) is publishing this regular biweekly notice. The Act requires the Commission publish notice of any amendments issued, or proposed to be issued and grants the Commission the authority to issue and make immediately effective any amendment to an operating license upon a determination by the Commission that such amendment involves no significant hazards consideration, notwithstanding the pendency before the Commission of a request for a hearing from any person.

This biweekly notice includes all notices of amendments issued, or proposed to be issued from September 22, 2011 to October 5, 2011. The last biweekly notice was published on October 4, 2011(76 FR 61391).

Addresses: Please include Docket ID NRC–2011–0241 in the subject line of your comments. Comments submitted in writing or in electronic form will be posted on the NRC Web site and on the Federal rulemaking Web site *http://www.regulations.gov.* Because your comments will not be edited to remove any identifying or contact information, the NRC cautions you against including any information in your submission that you do not want to be publicly disclosed.

The NRC requests that any party soliciting or aggregating comments received from other persons for submission to the NRC inform those persons that the NRC will not edit their comments to remove any identifying or contact information, and therefore, they should not include any information in their comments that they do not want publicly disclosed.

You may submit comments by any one of the following methods.

- *Federal Rulemaking Web Site:* Go to *http://www.regulations.gov* and search for documents filed under Docket ID NRC–2011–0241. Address questions about NRC dockets to Carol Gallagher 301–492–3668; e-mail *Carol.Gallagher@nrc.gov.*
- *Mail comments to:* Chief, Rules, Announcements, and Directives Branch (RADB), Office of Administration, Mail Stop: TWB–05–B01M, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.
- *Fax comments to:* RADB at 301–492–3446.

You can access publicly available documents related to this notice using the following methods:

- *NRC's Public Document Room (PDR):* The public may examine and have copied, for a fee, publicly available documents at the NRC's PDR, O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* Publicly available documents created or received at the NRC are accessible electronically through ADAMS in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html.* From this page, the public can gain entry into ADAMS, which provides text and image files of the NRC's public documents. If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC's PDR reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr.resource@nrc.gov.*
- *Federal Rulemaking Web Site:* Public comments and supporting materials related to this notice can be found at *http://www.regulations.gov* by searching on Docket ID: NRC–2011–0241.

Notice of Consideration of Issuance of Amendments to Facility Operating Licenses, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing

The Commission has made a proposed determination that the following amendment requests involve no significant hazards consideration. Under the Commission's regulations in Title 10 of the Code of Federal Regulations (10 CFR), Section 50.92, this means that operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. The basis for this proposed determination for each amendment request is shown below.

The Commission is seeking public comments on this proposed determination. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determination.

Normally, the Commission will not issue the amendment until the expiration of 60 days after the date of publication of this notice. The Commission may issue the license amendment before expiration of the 60-day period provided that its final determination is that the amendment involves no significant hazards consideration. In addition, the Commission may issue the amendment prior to the expiration of the 30-day comment period should circumstances change during the 30-day comment period such that failure to act in a timely way would result, for example in derating or shutdown of the facility. Should the Commission take action prior to the expiration of either the comment period or the notice period, it will publish in the **Federal Register** a notice of issuance. Should the Commission make a final No Significant Hazards Consideration Determination, any hearing will take place after issuance. The Commission expects that the need to take this action will occur very infrequently.

Within 60 days after the date of publication of this notice, any person(s) whose interest may be affected by this action may file a request for a hearing and a petition to intervene with respect to issuance of the amendment to the subject facility operating license. Requests for a hearing and a petition for leave to intervene shall be filed in accordance with the Commission's ''Rules of Practice for Domestic Licensing Proceedings'' in 10 CFR Part 2. Interested person(s) should consult a current copy of 10 CFR 2.309, which is available at the Commission's PDR, located at One White Flint North, Public File Area O1F21, 11555 Rockville Pike (first floor), Rockville, Maryland. NRC regulations are accessible electronically from the NRC Library on the NRC Web site at *http://www.nrc.gov/reading-rm/doc-collections/cfr/.* If a request for a hearing or petition for leave to intervene is filed by the above date, the Commission or a presiding officer designated by the Commission or by the Chief Administrative Judge of the Atomic Safety and Licensing Board Panel, will rule on the request and/or petition; and the Secretary or the Chief Administrative Judge of the Atomic Safety and Licensing Board will issue a notice of a hearing or an appropriate order.

As required by 10 CFR 2.309, a petition for leave to intervene shall set forth with particularity the interest of the petitioner in the proceeding, and how that interest may be affected by the results of the proceeding. The petition should specifically explain the reasons why intervention should be permitted with particular reference to the following general requirements: (1) The name, address, and telephone number of the requestor or petitioner; (2) the nature of the requestor's/petitioner's right under the Act to be made a party to the proceeding; (3) the nature and extent of the requestor's/petitioner's property, financial, or other interest in the proceeding; and (4) the possible effect of any decision or order which may be entered in the proceeding on the requestor's/petitioner's interest. The petition must also identify the specific contentions which the requestor/petitioner seeks to have litigated at the proceeding.

Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the requestor/petitioner shall provide a brief explanation of the bases for the contention and a concise statement of the alleged facts or expert opinion which support the contention and on which the requestor/petitioner intends to rely in proving the contention at the hearing. The requestor/petitioner must also provide references to those specific sources and documents of which the petitioner is aware and on which the requestor/petitioner intends to rely to establish those facts or expert opinion. The petition must include sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. Contentions shall be limited to matters within the scope of the amendment under consideration. The contention must be one which, if proven, would entitle the requestor/petitioner to relief. A requestor/petitioner who fails to satisfy these requirements with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing.

If a hearing is requested, the Commission will make a final determination on the issue of no significant hazards consideration. The final determination will serve to decide when the hearing is held. If the final determination is that the amendment request involves no significant hazards consideration, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing held would take place after issuance of the amendment. If the final determination is that the amendment request involves a significant hazards consideration, any hearing held would take place before the issuance of any amendment.

All documents filed in NRC adjudicatory proceedings, including a request for hearing, a petition for leave to intervene, any motion or other document filed in the proceeding prior to the submission of a request for hearing or petition to intervene, and documents filed by interested governmental entities participating under 10 CFR 2.315(c), must be filed in accordance with the NRC E-Filing rule (72 FR 49139, August 28, 2007). The E-Filing process requires participants to submit and serve all adjudicatory documents over the Internet, or in some cases to mail copies on electronic storage media. Participants may not submit paper copies of their filings unless they seek an exemption in accordance with the procedures described below.

To comply with the procedural requirements of E-Filing, at least ten (10) days prior to the filing deadline, the participant should contact the Office of the Secretary by e-mail at *hearing.docket@nrc.gov,* or by telephone at (301) 415–1677, to request (1) a digital ID certificate, which allows the participant (or its counsel or representative) to digitally sign documents and access the E-Submittal server for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a request or petition for hearing (even in instances in which the participant, or its counsel or representative, already holds an NRC-issued digital ID certificate). Based upon this information, the Secretary will establish an electronic docket for the hearing in this proceeding if the Secretary has not already established an electronic docket.

Information about applying for a digital ID certificate is available on NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals/apply-certificates.html.* System requirements for accessing the E-Submittal server are detailed in NRC's ''Guidance for Electronic Submission,'' which is available on the agency's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* Participants may attempt to use other software not listed on the Web site, but should note that the NRC's E-Filing system does not support unlisted software, and the NRC Meta System Help Desk will not be able to offer assistance in using unlisted software.

If a participant is electronically submitting a document to the NRC in accordance with the E-Filing rule, the participant must file the document using the NRC's online, Web-based submission form. In order to serve documents through EIE, users will be required to install a Web browser plug-in from the NRC Web site. Further information on the Web-based submission form, including the installation of the Web browser plug-in, is available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.*

Once a participant has obtained a digital ID certificate and a docket has been created, the participant can then submit a request for hearing or petition for leave to intervene. Submissions should be in Portable Document Format (PDF) in accordance with NRC guidance available on the NRC public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* A filing is considered complete at the time the documents are submitted through the NRC's E-Filing system. To be timely, an electronic filing must be submitted to the E-Filing system no later than 11:59 p.m. Eastern

Time on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an e-mail notice confirming receipt of the document. The E-Filing system also distributes an e-mail notice that provides access to the document to the NRC Office of the General Counsel and any others who have advised the Office of the Secretary that they wish to participate in the proceeding, so that the filer need not serve the documents on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before a hearing request/petition to intervene is filed so that they can obtain access to the document via the E-Filing system.

A person filing electronically using the agency's adjudicatory E-Filing system may seek assistance by contacting the NRC Meta System Help Desk through the ''Contact Us'' link located on the NRC Web site at *http://www.nrc.gov/site-help/e-submittals.html,* by e-mail at *MSHD.Resource@nrc.gov,* or by a toll-free call at (866) 672–7640. The NRC Meta System Help Desk is available between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday, excluding government holidays.

Participants who believe that they have a good cause for not submitting documents electronically must file an exemption request, in accordance with 10 CFR 2.302(g), with their initial paper filing requesting authorization to continue to submit documents in paper format. Such filings must be submitted by: (1) First class mail addressed to the Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemaking and Adjudications Staff; or (2) courier, express mail, or expedited delivery service to the Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, Maryland, 20852, Attention: Rulemaking and Adjudications Staff. Participants filing a document in this manner are responsible for serving the document on all other participants. Filing is considered complete by first-class mail as of the time of deposit in the mail, or by courier, express mail, or expedited delivery service upon depositing the document with the provider of the service. A presiding officer, having granted an exemption request from using E-Filing, may require a participant or party to use E-Filing if the presiding officer subsequently determines that the reason for granting the exemption from use of E-Filing no longer exists.

Documents submitted in adjudicatory proceedings will appear in NRC's electronic hearing docket which is available to the public at *http://ehd1.nrc.gov/ehd/,* unless excluded pursuant to an order of the Commission, or the presiding officer. Participants are requested not to include personal privacy information, such as social security numbers, home addresses, or home phone numbers in their filings, unless an NRC regulation or other law requires submission of such information. With respect to copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, participants are requested not to include copyrighted materials in their submission.

Petitions for leave to intervene must be filed no later than 60 days from the date of publication of this notice. Non-timely filings will not be entertained absent a determination by the presiding officer that the petition or request should be granted or the contentions should be admitted, based on a balancing of the factors specified in 10 CFR 2.309(c)(1)(i)-(viii).

For further details with respect to this license amendment application, see the application for amendment which is available for public inspection at the Commission's PDR, located at One White Flint North, Public File Area O1F21, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available documents created or received at the NRC are accessible electronically through ADAMS in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS, should contact the NRC PDR Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr.resource@nrc.gov.*

Calvert Cliffs Nuclear Power Plant, LLC, Docket Nos. 50–317 and 50–318, Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2, Calvert County, Maryland

Date of amendments request: August 31, 2011.

Description of amendments request: The amendment would revise Technical Specification (TS) 3.4.1, ''RCS [reactor coolant system] Pressure, Temperature, and Flow Departure from Nuclear Boiling (DNB) Limits,'' the bases for TS 3.4.1 and TS 5.6.5, ''Core Operating Limits Report (COLR),'' by replacing the DNB numeric limits with references to the COLR. The proposed changes are consistent with TS Task Force (TSTF) change traveler TSTF–487–A, Revision 1, ''Relocate DNB Parameters to the COLR.''

Basis for proposed no significant hazards consideration determination: As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

1. [Would the amendment involve] a significant increase in the probability or consequences of an accident previously evaluated?

No.

The proposed amendment replaces the limit values of the Reactor Coolant System (RCS) departure from nucleate boiling (DNB) parameters *i.e.,* pressurizer pressure, RCS cold leg temperature and RCS flow rate in the Technical Specifications (TS) with references to the Core Operating Limits Report (COLR), in accordance with the guidance of Generic Letter 88–16, to allow these parameter limit values to be recalculated without a license amendment. The proposed amendment does not involve operation of any required structures, systems, or components in a manner or configuration different from those previously recognized or evaluated. The cycle-specific values in the COLR must be calculated using the NRC [Nuclear Regulatory Commission] approved methodologies listed in TS 5.6.5, ''Core Operating Limits Report (COLR).'' Replacing the RCS DNB parameter limits in the TS with references to the COLR will maintain existing operating fuel cycle analysis requirements. Because these parameter limits are determined using NRC-approved methodologies, the acceptance criteria established for the safety analyses of various transients and accidents will continue to be met.

Therefore, neither the probability nor consequences of any accident previously evaluated will be increased by the proposed change.

The proposed administrative change to remove an outdated note from TS 3.4.1.c and SR [surveillance requirement] 3.4.1.3 does not affect any analyzed accident initiators, nor does it affect the unit's ability to successfully respond to any previously evaluated accident. In addition, the proposed amendment does not change the operation or maintenance that is performed on plant equipment.

Therefore, operation of the facility in accordance with the proposed amendment does not involve a significant increase in the probability of consequences of an accident previously evaluated.

2. [Would the amendment create] the possibility of a new or different type of accident from any accident previously evaluated?

No.

The proposed amendment to replace the RCS DNB parameter limits in the TS with references to the COLR does not involve a physical alteration of the plant, nor a change or addition of a system function. The proposed amendment does not involve

operation of any required system, structure, or component in a manner or configuration different from those previously recognized or evaluated. No new failure mechanisms will be introduced by the proposed change.

The proposed administrative change to remove an outdated note from TS 3.4.1.c and SR 3.4.1.3 does not involve a physical alteration to the plant (no new or different type of equipment will be installed) or a change in the methods governing normal plant operation.

Therefore, the proposed amendment does not create the possibility or a new or different kind of accident from any previously evaluated.

3. [Would the amendment involve] a significant reduction in a margin of safety?

No.

The proposed amendment to replace the RCS DNB parameter limits in the TS with references to the COLR will continue to maintain the margin of safety. The DNB parameter limits specified in the COLR will be determined based on the safety analysis of transients and accidents, performed using NRC-approved methodologies that show that, with appropriate measurement uncertainties of the parameters accounted for, the acceptance criteria for each of the analyzed transients are met. This provides the same margin of safety as the limit values currently specified in the TS. Any future revisions to the safety analyses that require prior NRC approval are identified per the 10 CFR [Code of Federal Regulations] 50.59 review process.

The proposed administrative change removes an outdated note from TS 3.4.1.c and SR 3.4.1.3. Since this is an administrative change, the safety function of plant equipment and their response to any analyzed accident are unaffected by this proposed change and, thus, there is no reduction in any margin of safety.

Therefore, the proposed amendment would not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendments request involves no significant hazards consideration.

Attorney for licensee: Carey Fleming, Sr. Counsel—Nuclear Generation, Constellation Generation Group, LLC, 750 East Pratt Street, 17th floor, Baltimore, MD 21202.

NRC Branch Chief: Nancy L. Salgado.

Exelon Generation Company, LLC, Docket No. 50–461, Clinton Power Station, Unit No.1, DeWitt County, Illinois

Date of amendment request: August 15, 2011.

Description of amendment request: The proposed amendment would revise the Limiting Condition for Operation (LCO) 3.8.1, ''AC Sources—Operating,'' through a reduction to the maximum steady state voltage criteria for safety-related 4.16 kV buses from 4580 V to 4300 V in certain Technical Specification (TS) Section 3.8.1 Surveillance Requirements.

Basis for proposed no significant hazards consideration determination: As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration which is presented below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed change does not significantly increase the probability of an accident previously evaluated in the Updated Safety Analysis Report (USAR). The revised steady state voltage ensures that the diesel generators (DGs) and equipment powered by the DGs will continue to function as required to mitigate accidents as described in the USAR. The DGs and the equipment they power are part of the systems required to mitigate an accident. Mitigation equipment is not a factor in accident initiation.

Therefore, the probability of a previously evaluated accident will not significantly increase due to operating in the proposed manner.

The reduction of the DG maximum steady state voltage limit ensures that the DGs and the safety-related components downstream of the DG are operated within their design limitations; therefore, the consequences of an accident previously evaluated in the USAR will not be increased by operating in the proposed manner. The change to the DG maximum steady state voltage limit ensures the DGs and equipment powered by the DGs will perform as analyzed and mitigate the consequences of any accident described in the USAR.

Therefore, the change in the maximum steady state voltage limit is within the bounds of previous analysis in the USAR and does not involve an increase in the consequences of an accident previously evaluated.

Therefore, the proposed change does not involve a significant increase in the probability or consequence of any previously evaluated accident.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

This TS amendment request does not involve any changes to the operation, testing, or maintenance of any safety-related, or otherwise important to safety system. All systems that are important to safety will continue to be operated and maintained within their design bases. The proposed changes to LCO 3.8.1 will resolve a non-conservatism, which will serve to ensure that all associated systems and components are operated reliably within their design capabilities.

Since all systems will continue to be operated within their design capabilities, no new failure modes are introduced, nor is the possibility of a new or different kind of accident created through operation in the proposed manner.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed change is limited to the diesel generator maximum steady state voltage limit acceptance criterion in TS 3.8.1 Surveillance Requirements. No other surveillance criterion is affected. The surveillance frequencies and test requirements are unchanged. The proposed change provides increased assurance that the diesel generators and equipment powered by the diesel generators will perform as designed.

Therefore, the proposed amendment does not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

Attorney for licensee: Mr. Bradley J. Fewell, Associate General Counsel, Exelon Generation Company, LLC, 4300 Winfield Road, Warrenville, IL 60555.

NRC Branch Chief: Jacob I. Zimmerman.

FirstEnergy Nuclear Operating Company (FENOC), Docket Nos. 50–334 and 50–412, Beaver Valley Power Station (BVPS), Unit Nos. 1 and 2, Beaver County, Pennsylvania

Docket No. 50–346, Davis-Besse Nuclear Power Station, Unit No. 1 (DBNPS), Ottawa County, Ohio

Docket No. 50–440, Perry Nuclear Power Plant, Unit No. 1 (PNPP), Lake County, Ohio

Date of amendment request: September 20, 2011.

Description of amendment request: The proposed amendment would revise the licenses of BVPS, Unit Nos. 1 and 2, DBNPS and PNPP to reflect the name change of an owner licensee from ''FirstEnergy Nuclear Generation Corp.'' to ''FirstEnergy Nuclear Generation, LLC.'' The proposed amendment is administrative in nature. The proposed amendment will also correct errors regarding the name of FirstEnergy Nuclear Generation Corp in the DBNPS and PNNP Facility Operating Licenses.

Basis for proposed no significant hazards consideration determination: As required by Title 10 of the Code of Federal Regulations (CFR), Section 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed amendment changes the name of an owner licensee. The proposed amendment is considered administrative in nature. The functions of the owner licensee will not change. There is no impact upon the other facility licensees. FENOC will remain the operator of the facilities. The proposed amendment does not alter the design, function, or operation of any plant equipment. As such, the accident and transient analyses contained in the facility updated final safety analysis reports will not be impacted.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed amendment is considered administrative in nature. The functions of the owner licensee will not change. The proposed amendment does not alter the design, function, or operation of any plant equipment.

Therefore, the proposed change does not create the possibility of a new of different kind of accident from any previously identified.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed amendment changes the name of an owner licensee. The proposed amendment is considered administrative in nature. The functions of the owner licensee will not change. There is no impact upon the other facility licensees. FENOC will remain the operator of the facilities. The proposed amendment does not alter the design, function, or operation of any plant equipment. As such, the accident and transient analyses contained in the facility updated final safety analysis reports will not be impacted.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the requested amendments involve no significant hazards consideration.

Attorney for licensee: David W. Jenkins, Attorney, FirstEnergy Corporation, 76 South Main Street, Akron, Ohio 44308.

NRC Branch Chief: Jacob I. Zimmerman.

Florida Power and Light Company (FPL), Docket Nos. 50–250 and 50–251, Turkey Point Plant, Units 3 and 4, Miami-Dade County, Florida

Date of amendment request: May 25, 2011.

Description of amendment request: The proposed changes would relocate the specifications in Section 5.2—Containment, Section 5.4—Reactor Coolant System, and Section 5.6—Component Cyclic or Transient Limit, to the Updated Final Safety Analysis Report (UFSAR). Technical Specification (TS) 5.5.3 regarding spent fuel storage pool capacity would be revised to a total pool capacity limit only. This application also satisfies FPL commitments in Turkey Point Licensee Event Report 05000250/2010–001–01 dated November 22, 2010, and FPL letter L–2011–032 dated February 22, 2011.

Basis for proposed no significant hazards consideration determination: As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

FPL has evaluated these TS changes to determine if a significant hazard is present. The No Significant Hazards Consideration evaluation required by 10 CFR 50.92 is provided below.

(1) Would operation of the facility in accordance with the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The deletion of TSs 5.2, 5.4 and 5.6 with design values and cyclic or transient limits relocated to the FSAR, and the relocation of storage rack capacities in TS 5.5.3 to the FSAR are administrative in nature. The TS changes do not represent any physical change to plant systems, structures, or components, or to procedures established for plant operation.

Therefore, initial conditions associated with and systems credited for mitigating the consequences of accidents previously evaluated remain unchanged.

Therefore, facility operation in accordance with the proposed amendment would not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) Would operation of the facility in accordance with the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The deletion of TSs 5.2, 5.4 and 5.6 with design values and cyclic or transient limits relocated to the FSAR, and the relocation of storage rack capacities in TS 5.5.3 to the FSAR are administrative in nature. The TS changes do not represent any physical change to plant systems, structures, or components, or to procedures established for plant operation. Because the proposed changes are administrative and do not alter or create a new mode of plant operation or configuration, the possibility of a new or different kind of accident is not created.

Therefore, operation of the facility in accordance with the proposed amendment would not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) Would operation of the facility in accordance with the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

The deletion of TSs 5.2, 5.4 and 5.6 with design values and cyclic or transient limits relocated to the FSAR, and the relocation of storage rack capacities in TS 5.5.3 to the FSAR are administrative in nature. The TS changes do not represent any physical change to plant systems, structures, or components, or to procedures established for plant operation. Because the proposed changes are administrative and do not alter or create a new mode of plant operation or configuration, margins of safety are unchanged.

Therefore, operation of the facility in accordance with the proposed amendment will not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

Attorney for licensee: M.S. Ross, Attorney, Florida Power & Light, P.O. Box 14000, Juno Beach, Florida 33408–0420.

NRC Branch Chief: Douglas A. Broaddus.

Florida Power and Light Company (FPL), Docket Nos. 50–250 and 50–251, Turkey Point Plant, Units 3 and 4, Miami-Dade County, Florida

Date of amendment request: August 5, 2011.

Description of amendment request: The proposed amendment would modify Technical Specification (TS) Surveillance Requirements (SR) 4.8.2.1 pertaining to periodic verification of battery bank capacity and intercell and connection resistance.

Basis for proposed no significant hazards consideration determination: As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

(a) Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed changes are to the surveillance requirements only. The ability of the TS surveillance to ensure that the batteries have the capacity to perform their specified safety functions with regard to accident mitigation or meeting their licensing design basis requirements is not reduced/diminished.

There are no design changes associated with this TS amendment. The DC power system/batteries will remain designed with adequate independency, redundancy, capacity and testability to permit the functioning required of the engineered safety features. The batteries will each continue to independently provide this capacity assuming a failure of a single active component.

The proposed changes will not affect accident initiators or precursors, not adversely alter the design assumptions, conditions, and configuration of the facility or the manner in which the plant is operated. The proposed changes will not alter or prevent the ability of structures, systems and components from performing their intended functions to mitigate the consequences of an initiating event.

The proposed changes do not physically alter safety related systems nor affect the way in which safety related systems perform their function.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

(b) Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed changes are to the surveillance requirements only. The ability of the TS surveillance to ensure that the batteries have the capacity to perform their specified safety functions with regard to accident mitigation or meeting their licensing design basis requirements is not reduced/diminished.

There are no proposed design changes nor are there any changes in the method by which any safety related plant structure, system, or component (SSC) performs its specified safety function. The proposed changes will not affect the normal method of plant operation or change any operating parameters. Equipment performance necessary to fulfill safety analysis missions will be unaffected. The proposed change will not alter any assumptions required to meet the safety analysis acceptance criteria.

No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures will be introduced as a result of this amendment. There will be no adverse effect or challenges imposed on any safety related system as a result of this amendment.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

(c) Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed changes do not reduce the ability of the TS surveillance requirements to ensure that the station batteries have adequate capacity to perform their engineered safety features functions with regard to accident mitigation and meeting their licensing design basis requirements. The lower battery inter-cell connection resistance values are more restrictive, consistent with design basis calculations and appropriately identified in maintenance procedures. In addition, the battery connections quality is also inherently validated by the TS SR battery performance testing. The new values for the battery capacity and service life surveillance requirements are more restrictive and more appropriate acceptance criteria for verifying battery performance. The reduction in surveillance intervals for a battery showing signs of degradation from 18 months to 12 months is more conservative.

The proposed changes do not physically alter safety related systems. There will be no effect on those plant systems necessary to assure the accomplishment of protection functions. There will be no impact on the overpower limit, departure from nucleate boiling (DNBR) limits, loss of cooling accident peak cladding temperature (LOCA PCT), or any other margin of safety. The applicable radiological dose consequence acceptance criteria will continue to be met.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

Attorney for licensee: M.S. Ross, Attorney, Florida Power & Light, P.O. Box 14000, Juno Beach, Florida 33408–0420.

NRC Branch Chief: Douglas A. Broaddus.

Florida Power and Light Company (FPL), Docket Nos. 50–250 and 50–251, Turkey Point Plant, Units 3 and 4, Miami-Dade County, Florida

Date of amendment request: August 17, 2011.

Description of amendment request: The application proposes changes to Technical Specifications (TSs) Limiting Condition for Operation of TS 3.3.3.3, Tables 3.3–5, Accident Monitoring Instrumentation, High Range-Noble Gas Effluent Monitors, Main Steam Lines, Instrument 19d, and conforming changes to TS 4.3.3.3, Table 4.3–4, Accident Monitoring Instrumentation Surveillance Requirements, Instrument 19d.

The Main Steam Lines High Range Noble Gas Effluent Monitor, RAD–6426, is used in post-accident monitoring in response to the requirements of Regulatory Guide 1.97, Revision 3. As a Category 2, Type E instrument, RAD–6426 does not meet any of the Title 10 of the Code of Federal Regulations Section 50.36(c)(2)(ii) screening criteria for inclusion in the TSs Post Accident Monitoring Table. The proposed changes would relocate the TS and surveillance requirements for this instrument to the Updated Final Safety Analysis Report and related procedures.

Basis for proposed no significant hazards consideration determination: As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

FPL has evaluated the proposed Technical Specification (TS) changes to determine if a significant hazard is present. The No Significant Hazards Consideration evaluation required by 10 CFR 50.92 is provided below.

1. The proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

The Main Steam Line High-Range Noble Gas Effluent monitor is not an event initiator, nor is it credited in the mitigation of any event. Thus, the initiating conditions and assumptions for accidents described in the Updated Final Safety Analysis Report (UFSAR) remain as analyzed. The function of the Main Steam Line High-Range Noble Gas Effluent monitor is to detect and quantify noble gas volumetric activity released from the Main Steam Safety Valves and/or the Atmospheric Dump Valves during and following an accident. The Main Steam Line monitors are used in the Emergency Plan to determine event action levels. The use of the monitors in the Off-Normal Operating Procedures, in the Emergency Operating Procedures, and Emergency Plan Implementing Procedures (to determine if a release is in progress) will not change. Relocation of the technical specification and surveillance requirements to the UFSAR and related procedures does not impact the accident analyses in any manner.

Based on the above, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. The proposed amendment does not create the possibility of a new or different kind of accident from any previously evaluated.

The function of the Main Steam Line High-Range Noble Gas Effluent monitor is to detect and quantify noble gas volumetric activity released from the Main Steam Safety Valves and/or the Atmospheric Dump Valves during and following an accident. This function will not change as a result of the proposed TS changes. Procedural use of the monitor function, surveillance or calibration frequency of the monitor to determine operability will not change as a result of the proposed relocation of the technical specification and surveillance requirements to the UFSAR and related procedures.

Based on the above, the proposed change does not create the possibility of a new or

different kind of accident from any previously evaluated.

3. The proposed amendment does not involve a significant reduction in a margin of safety.

The function of the Main Steam Line High-Range Noble Gas Effluent monitor is to detect and quantify noble gas volumetric activity released from the Main Steam Safety Valves and/or the Atmospheric Dump Valves during and following an accident. The relocation of the technical specification and surveillance requirements of this monitor to the UFSAR and related procedures does not affect the manner in which any safety limits, limiting safety system settings, or limiting conditions for operation are determined. The safety analyses are not affected by the proposed TS changes. The proposed changes do not result in plant operation outside of design bases, because the function and surveillance of the monitor for operability remain unchanged.

Based on the above, operation in accordance with the proposed amendment would not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the amendment request involves no significant hazards consideration.

Attorney for licensee: M.S. Ross, Attorney, Florida Power & Light, P.O. Box 14000, Juno Beach, Florida 33408–0420.

NRC Branch Chief: Douglas A. Broaddus.

Notice of Issuance of Amendments to Facility Operating Licenses

During the period since publication of the last biweekly notice, the Commission has issued the following amendments. The Commission has determined for each of these amendments that the application complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendment.

Notice of Consideration of Issuance of Amendment to Facility Operating License, Proposed No Significant Hazards Consideration Determination, and Opportunity for A Hearing in connection with these actions was published in the **Federal Register** as indicated.

Unless otherwise indicated, the Commission has determined that these amendments satisfy the criteria for categorical exclusion in accordance with 10 CFR 51.22. Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared for these amendments. If the Commission has prepared an environmental assessment under the special circumstances provision in 10 CFR 51.22(b) and has made a determination based on that assessment, it is so indicated.

For further details with respect to the action see (1) the applications for amendment, (2) the amendment, and (3) the Commission's related letter, Safety Evaluation and/or Environmental Assessment as indicated. All of these items are available for public inspection at the Commission's Public Document Room (PDR), located at One White Flint North, Public File Area 01F21, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available documents created or received at the NRC are accessible electronically through the Agencywide Documents Access and Management System (ADAMS) in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html.* If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the PDR Reference staff at 1–800–397–4209, 301–415–4737 or by e-mail to *pdr.resource@nrc.gov.*

Detroit Edison Company, Docket No. 50–341, Fermi 2, Monroe County, Michigan

Date of application for amendment: September 24, 2010, supplemented by letter dated March 4, 2011.

Brief description of amendment: The amendment revises the licensing basis, specifically the Radiological Emergency Response Preparedness (RERP) Plan, to increase the staff augmentation times for the Operational and Technical Support Centers-related functions from 30 to 60 minutes, and for Emergency Operations Facility-related functions from 60 to 90 minutes.

Date of issuance: September 23, 2011.

Effective date: As of the date of issuance and shall be implemented within 60 days.

Amendment No.: 187.

Facility Operating License No. NPF–43: Amendment revised the Operating License.

Date of initial notice in ***Federal Register:*** November 30, 2010 (75 FR 74093).

The supplemental letter contained clarifying information and did not change the initial no significant hazards consideration determination, and did not expand the scope of the original application. The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated September 23, 2011.

No significant hazards consideration comments received: No.

Dominion Nuclear Connecticut, Inc., et al., Docket Nos. 50–336 and 50–423, Millstone Power Station, Unit Nos. 2 and 3, New London County, Connecticut

Date of application for amendment: July 12, 2010, as supplemented by letters dated August 5, 2010, September 23, 2010, November 10, 2010, December 13, 2010, April 4, 2011, May 17, 2011, and August 4, 2011.

Brief description of amendment: The amendment approves the Cyber Security Plan (CSP) and associated implementation schedule, and revises the license condition regarding physical protection to reflect such approval. The amendment specifies that the licensee fully implement and maintain in effect all provisions of the Commission-approved CSP as required by 10 CFR 73.54.

Date of issuance: September 30, 2011.

Effective date: As of the date of issuance and shall be implemented according to the schedule conveyed in the licensee's April 4, 2011, letter.

Amendment Nos.: 309 and 251.

Renewed Facility Operating License Nos. DPR–65 and NPF–49: Amendment revised the respective Licenses.

Date of initial notice in ***Federal Register:*** February 1, 2011 (76 FR 5616). The supplemental letters contain clarifying information, did not change the scope of the license amendment request, did not change the NRC staff's initial proposed finding of no significant hazards consideration determination, and did not expand the scope of the original **Federal Register** notice.

The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated September 30, 2011.

No significant hazards consideration comments received: No.

Exelon Generation Company, LLC, Docket No. 50–461, Clinton Power Station, Unit No. 1, DeWitt County, Illinois

Date of application for amendment: October 8, 2010, as supplemented by letters dated January 6, February 24, and March 8, 2011.

Brief description of amendment: This amendment revised technical specification (TS) 3.8.3, ''Diesel Fuel Oil, Lube Oil, and Starting Air,'' by relocating the current stored diesel fuel oil and lube oil numerical volume requirements from the TS to the TS Bases so that they may be modified under licensee control. The TS were

modified so that the stored diesel fuel oil and lube oil inventory would require that a 7-day supply be available for each diesel generator. Condition A and Condition B in the Action table were revised and Surveillance Requirements (SRs) 3.8.3.1 and 3.8.3.2 were revised to reflect the above change.

Date of issuance: October 4, 2011

Effective date: As of the date of issuance and shall be implemented within 60 days.

Amendment No.: 196.

Facility Operating License No. NPF–62: The amendment revised the TSs and license.

Date of initial notice in ***Federal Register:*** May 26, 2010 (76 FR 6833) The supplemental letters dated January 6, February 24, and March 8, 2011 contained clarifying information and did not change the NRC staff's initial proposed finding of no significant hazards consideration.

The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated October 4, 2011.

No significant hazards consideration comments received: No.

Exelon Generation Company, LLC, Docket Nos. 50–237 and 50–249, Dresden Nuclear Power Station, Units 2 and 3, Grundy County, Illinois

Date of application for amendment: October 4, 2011, as supplemented by letter dated April 6, 2011.

Brief description of amendment: The amendment revises the applicability of Technical Specification 3.3.1.1, ''Reactor Protection System Instrumentation'' Function 5 (*i.e.,* ''Main Steam Isolation valve—Closure'') and Function 10 (*i.e.,* ''Turbine Condenser Vacuum—Low'') for Dresden Nuclear Power Station Units 2 and 3. The change enables the implementation of a modification that will eliminate these functions with the reactor switch in STARTUP while in Mode 2 with reactor pressure greater than or equal to 600 pounds per square inch (psig).

Date of issuance: October 4, 2011.

Effective date: As of the date of issuance and shall be implemented during the next outage of sufficient duration.

Amendment Nos.: 239, 232.

Renewed Facility Operating License Nos. DPR–19 and DPR–25: The amendments revised the Technical Specifications and License.

Date of initial notice in ***Federal Register:*** February 1, 2011 (76 FR 5619).

The April 6, 2011, supplement contained clarifying information and did not change the NRC staff's initial proposed finding of no significant hazards consideration.

The Commission's related evaluation of the amendments is contained in a Safety Evaluation dated October 4, 2011.

No significant hazards consideration comments received: No.

Exelon Generation Company, LLC, and PSEG Nuclear, LLC, Docket No. 50–278, Peach Bottom Atomic Power Station (PBAPS), Unit 3, York and Lancaster Counties, Pennsylvania

Date of application for amendments: June 8, 2011, as supplemented on August 19, 2011, and September 9, 2011.

Brief description of amendments: The amendment modifies the PBAPS Unit 3 Technical Specification (TS) Section 2.1.1.2 to reflect revised Safety Limit Minimum Critical Power Ratio (SLMCPR) values for Operating Cycle 19. The SLMCPR analysis establishes SLMCPR values that will ensure that during normal operation and during abnormal operational transients, at least 99.9 percent of all fuel rods in the core do not experience transition boiling if the limit is not violated.

Date of issuance: September 30, 2011.

Effective date: As of the date of issuance and shall be implemented within 30 days from the date of issuance.

Amendment No.: 284.

Renewed Facility Operating License No. DPR–56: Amendment revises the Technical Specifications.

Date of initial notice in ***Federal Register:*** August 22, 2011 (76 FR 52357).

The supplements dated August 19, 2011 and September 9, 2011, clarified the application, did not expand the scope of the application as originally noticed, and did not change the initial proposed no significant hazards consideration (NSHC) determination.

The Commission's related evaluation of the amendment and final NSHC determination are contained in a Safety Evaluation dated September 30, 2011.

No significant hazards consideration comments received: No.

Exelon Generation Company, LLC, and PSEG Nuclear, LLC, Docket Nos. 50–277 and 50–278, Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3, York and Lancaster Counties, Pennsylvania

Date of application for amendments: June 25, 2010, as supplemented on August 16, 2010, December 16, 2010, January 26, 2011, and March 25, 2011.

Brief description of amendments: The amendment revises Technical Specification Surveillance Requirement (SR) 3.6.1.3, ''Primary Containment Isolation Valves (PCIVs),'' and SR 3.6.1.5, ''Reactor Building-to-Suppression Chamber Vacuum Breakers,'' to modify the required level for the liquid nitrogen storage tank.

Date of issuance: September 30, 2011.

Effective date: As of the date of issuance and shall be implemented within 30 days from the date of issuance.

Amendment Nos.: 282 and 285.

Renewed Facility Operating License Nos. DPR–44 and DPR–56: Amendments revised the License and Technical Specifications.

Date of initial notice in ***Federal Register:*** November 30, 2010, (75 FR 74094). The supplements dated August 16, 2010, December 16, 2010, January 26, 2011, and March 25, 2011, clarified the application, did not expand the scope of the application as originally noticed, and did not change the initial proposed no significant hazards consideration determination.

The Commission's related evaluation of the amendments is contained in a Safety Evaluation dated September 30, 2011.

No significant hazards consideration comments received: No.

FirstEnergy Nuclear Operating Company, et al., Docket No. 50–440, Perry Nuclear Power Plant, Unit No. 1, Lake County, Ohio

Date of application for amendment: April 12, 2011.

Brief description of amendment: FirstEnergy Nuclear Operating Company, the licensee for the Perry Nuclear Power Plant Unit No. 1 (PNPP), requested to amend the PNPP Technical Specification (TS) to define a new time limit for restoring inoperable reactor coolant system (RCS) leakage detection instrumentation to operable status; establish alternate methods of monitoring RCS leakage when one or more required monitors are inoperable; and make TS Bases changes which reflect the proposed changes and more accurately reflect the contents of the facility design basis related to operability of the RCS leakage detection instrumentation. The request is consistent with the guidance contained in U.S. Nuclear Regulatory Commission (NRC)-approved Technical Specifications Task Force Change Traveler 514 (TSTF–514). TSTF–514 was made available by the NRC on, December 17, 2010 (75 FR 79048) as part of the consolidated line item improvement process.

Date of issuance: October 4, 2011.

Effective date: As of the date of issuance and shall be implemented within 90 days.

Amendment No.: 159.

Facility Operating License No. NPF–58: This amendment revised the Technical Specifications and License.

Date of initial notice in ***Federal Register:*** May 31, 2011 (76 FR 31373).

The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated October 4, 2011.

No significant hazards consideration comments received: No.

Nine Mile Point Nuclear Station, LLC, Docket No. 50–220, Nine Mile Point Nuclear Station, Unit No. 1 (NMP1), Oswego County, New York

Date of application for amendment: September 29, 2010.

Brief description of amendment: The amendment revises the NMP1 Technical Specifications (TS) Sections 3/4.1.5, ''Solenoid-Actuated Pressure Relief Valves (Automatic Depressurization System),'' and 3/4.2.9, ''Pressure Relief Systems-Solenoid-Actuated Pressure Relief Valves (Overpressurization),'' to provide for an alternative means of testing the main steam electromatic relief valves (ERVs). The proposed change allows demonstration of the capability of the valves to perform their safety function without requiring the ERVs to be cycled with reactor steam pressure while installed in the plant.

Date of issuance: September 28, 2011.

Effective date: As of the date of issuance to be implemented within 90 days.

Amendment No.: 210.

Renewed Facility Operating License No. DPR–63: The amendment revises the License and TSs.

Date of initial notice in ***Federal Register:*** February 22, 2011 (76 FR 9826).

The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated September 28, 2011.

No significant hazards consideration comments received: No.

Omaha Public Power District, Docket No. 50–285, Fort Calhoun Station, Unit No. 1, Washington County, Nebraska

Date of amendment request: August 16, 2010, as supplemented by letters dated September 27, 2010, April 6, 2011, and June 30, 2011.

Brief description of amendment: The amendment revised the Fort Calhoun Station, Unit 1 (FCS) Technical Specifications (TSs) to relocate the operating and surveillance requirements for the power-operated relief valve and pressurizer safety valve acoustic position indication and tail pipe temperature from TS 2.15, ''Instrumentation and Control Systems,'' Table 2–5, ''Instrumentation Operating Requirements for Other Safety Feature Functions,'' Items 3, 4, and 5 to the FCS Updated Safety Analysis Report. The amendment also revised the surveillance requirement, TS 3.1, ''Instrumentation and Control,'' Table 3–3, ''Minimum Frequencies for Checks, Calibrations and Testing of Miscellaneous Instrumentation and Controls,'' Items 21, 23, and 24. Additionally, the TS Table 2–5 associated Note 'e' was re-lettered to Note 'a' and TS Table 2–5 footnote 'i' to Note 'c' was deleted.

Date of issuance: September 30, 2011.

Effective date: This license amendment is effective as of the date of its issuance and shall be implemented within 90 days from the date of issuance.

Amendment No.: 268.

Renewed Facility Operating License No. DPR–40: The amendment revised the operating license and Technical Specifications.

Date of initial notice in ***Federal Register:*** January 25, 2011 (76 FR 4388). The supplemental letters dated September 27, 2010, April 6, 2011, and June 30, 2011, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the **Federal Register**. The Commission's related evaluation of the amendment is contained in a safety evaluation dated September 30, 2011.

No significant hazards consideration comments received: No.

Tennessee Valley Authority, Docket Nos. 50–259, 50–260, and 50–296, Browns Ferry Nuclear Plant, Units 1, 2, and 3, Limestone County, Alabama

Date of application for amendments: November 12, 2010, as supplemented on February 8, May 27, June 15, and August 19, 2011.

Description of amendment request: The changes extend the Completion Time (CT) specified in Technical Specification (TS) 3.8.1, ''AC Sources—Operating,'' for Emergency Diesel Generators (EDGs) A, B, C, D, 3A, 3B, 3C and 3D from 7 days to 14 days when one EDG is inoperable, provided a supplemental power source is available during the CT extension period.

Date of issuance: October 5, 2011.

Effective date: Date of issuance, to be implemented within 30 days.

Amendment Nos.: Unit 1—280, Unit 2—307, and Unit 3—266.

Renewed Facility Operating License Nos. DPR–33, DPR–52, and DPR–68: Amendments revised the licenses and TSs.

Date of initial notice in ***Federal Register:*** December 14, 2010 (75 FR 77917). The supplements dated February 8, May 27, June 15, and August 19, 2011, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the **Federal Register**.

The Commission's related evaluation of the amendment is contained in a Safety Evaluation dated October 5, 2011.

No significant hazards consideration comments received: No.

Virginia Electric and Power Company, Docket Nos. 50–338 and 50–339, North Anna Power Station, Units 1 and 2, Louisa County, Virginia

Date of application for amendment: April 27, 2011.

Brief description of amendment: These amendments revise Technical Specifications (TSs) 3.4.15 ''RCS [reactor coolant system] Leakage Detection Instrumentation.''

Date of issuance: September 28, 2011.

Effective date: As of the date of issuance and shall be implemented within 60 days from the date of issuance.

Amendment Nos.: 265/246.

Renewed Facility Operating License Nos. NPF–4 and NPF–7: Amendments change the licenses and the technical specifications. Specifically, the amendments define a new time limit for restoring inoperable RCS leakage detection instrumentation to operable status and establish alternate methods of monitoring RCS leakage when one or more required leakage detection monitors are inoperable.

Date of initial notice in ***Federal Register:*** May 31, 2011 (76 FR 31377).

The Commission's related evaluation of the amendments is contained in a Safety Evaluation dated September 28, 2011.

No significant hazards consideration comments received: No.

Notice of Issuance of Amendments to Facility Operating Licenses and Final Determination of No Significant Hazards Consideration and Opportunity for a Hearing (Exigent Public Announcement or Emergency Circumstances)

During the period since publication of the last biweekly notice, the Commission has issued the following amendments. The Commission has determined for each of these

amendments that the application for the amendment complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendment.

Because of exigent or emergency circumstances associated with the date the amendment was needed, there was not time for the Commission to publish, for public comment before issuance, its usual Notice of Consideration of Issuance of Amendment, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing.

For exigent circumstances, the Commission has either issued a **Federal Register** notice providing opportunity for public comment or has used local media to provide notice to the public in the area surrounding a licensee's facility of the licensee's application and of the Commission's proposed determination of no significant hazards consideration. The Commission has provided a reasonable opportunity for the public to comment, using its best efforts to make available to the public means of communication for the public to respond quickly, and in the case of telephone comments, the comments have been recorded or transcribed as appropriate and the licensee has been informed of the public comments.

In circumstances where failure to act in a timely way would have resulted, for example, in derating or shutdown of a nuclear power plant or in prevention of either resumption of operation or of increase in power output up to the plant's licensed power level, the Commission may not have had an opportunity to provide for public comment on its no significant hazards consideration determination. In such case, the license amendment has been issued without opportunity for comment. If there has been some time for public comment but less than 30 days, the Commission may provide an opportunity for public comment. If comments have been requested, it is so stated. In either event, the State has been consulted by telephone whenever possible.

Under its regulations, the Commission may issue and make an amendment immediately effective, notwithstanding the pendency before it of a request for a hearing from any person, in advance of the holding and completion of any required hearing, where it has determined that no significant hazards consideration is involved.

The Commission has applied the standards of 10 CFR 50.92 and has made a final determination that the amendment involves no significant hazards consideration. The basis for this determination is contained in the documents related to this action. Accordingly, the amendments have been issued and made effective as indicated.

Unless otherwise indicated, the Commission has determined that these amendments satisfy the criteria for categorical exclusion in accordance with 10 CFR 51.22. Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared for these amendments. If the Commission has prepared an environmental assessment under the special circumstances provision in 10 CFR 51.12(b) and has made a determination based on that assessment, it is so indicated.

For further details with respect to the action see (1) the application for amendment, (2) the amendment to Facility Operating License, and (3) the Commission's related letter, Safety Evaluation and/or Environmental Assessment, as indicated. All of these items are available for public inspection at the Commission's Public Document Room (PDR), located at One White Flint North, Public File Area 01F21, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available documents created or received at the NRC are accessible electronically through the Agencywide Documents Access and Management System (ADAMS) in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html*. If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the PDR Reference staff at 1 (800) 397–4209, (301) 415–4737 or by e-mail to *pdr.resource@nrc.gov.*

The Commission is also offering an opportunity for a hearing with respect to the issuance of the amendment. Within 60 days after the date of publication of this notice, any person(s) whose interest may be affected by this action may file a request for a hearing and a petition to intervene with respect to issuance of the amendment to the subject facility operating license. Requests for a hearing and a petition for leave to intervene shall be filed in accordance with the Commission's ''Rules of Practice for Domestic Licensing Proceedings'' in 10 CFR Part 2. Interested person(s) should consult a current copy of 10 CFR 2.309, which is available at the Commission's PDR, located at One White Flint North, Public File Area 01F21, 11555 Rockville Pike (first floor), Rockville, Maryland, and electronically on the Internet at the NRC Web site, *http://www.nrc.gov/reading-rm/doc-collections/cfr/*. If there are problems in accessing the document, contact the PDR Reference staff at 1–800–397–4209, 301–415–4737, or by e-mail to *pdr.resource@nrc.gov*. If a request for a hearing or petition for leave to intervene is filed by the above date, the Commission or a presiding officer designated by the Commission or by the Chief Administrative Judge of the Atomic Safety and Licensing Board Panel, will rule on the request and/or petition; and the Secretary or the Chief Administrative Judge of the Atomic Safety and Licensing Board will issue a notice of a hearing or an appropriate order.

As required by 10 CFR 2.309, a petition for leave to intervene shall set forth with particularity the interest of the petitioner in the proceeding, and how that interest may be affected by the results of the proceeding. The petition should specifically explain the reasons why intervention should be permitted with particular reference to the following general requirements: 1) the name, address, and telephone number of the requestor or petitioner; 2) the nature of the requestor's/petitioner's right under the Act to be made a party to the proceeding; 3) the nature and extent of the requestor's/petitioner's property, financial, or other interest in the proceeding; and 4) the possible effect of any decision or order which may be entered in the proceeding on the requestor's/petitioner's interest. The petition must also identify the specific contentions which the requestor/petitioner seeks to have litigated at the proceeding.

Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the requestor/petitioner shall provide a brief explanation of the bases for the contention and a concise statement of the alleged facts or expert opinion which support the contention and on which the petitioner intends to rely in proving the contention at the hearing. The petitioner must also provide references to those specific sources and documents of which the petitioner is aware and on which the petitioner intends to rely to establish those facts or expert opinion. The petition must include sufficient information to show that a genuine dispute exists with the applicant on a

material issue of law or fact.[1] Contentions shall be limited to matters within the scope of the amendment under consideration. The contention must be one which, if proven, would entitle the petitioner to relief. A requestor/petitioner who fails to satisfy these requirements with respect to at least one contention will not be permitted to participate as a party.

Each contention shall be given a separate numeric or alpha designation within one of the following groups:

1. Technical—primarily concerns/issues relating to technical and/or health and safety matters discussed or referenced in the applications.

2. Environmental—primarily concerns/issues relating to matters discussed or referenced in the environmental analysis for the applications.

3. Miscellaneous—does not fall into one of the categories outlined above.

As specified in 10 CFR 2.309, if two or more petitioners/requestors seek to co-sponsor a contention, the petitioners/requestors shall jointly designate a representative who shall have the authority to act for the petitioners/requestors with respect to that contention. If a requestor/petitioner seeks to adopt the contention of another sponsoring requestor/petitioner, the requestor/petitioner who seeks to adopt the contention must either agree that the sponsoring requestor/petitioner shall act as the representative with respect to that contention, or jointly designate with the sponsoring requestor/petitioner a representative who shall have the authority to act for the petitioners/requestors with respect to that contention.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing. Since the Commission has made a final determination that the amendment involves no significant hazards consideration, if a hearing is requested, it will not stay the effectiveness of the amendment. Any hearing held would take place while the amendment is in effect.

All documents filed in NRC adjudicatory proceedings, including a request for hearing, a petition for leave to intervene, any motion or other document filed in the proceeding prior to the submission of a request for hearing or petition to intervene, and documents filed by interested governmental entities participating under 10 CFR 2.315(c), must be filed in accordance with the NRC E–Filing rule (72 FR 49139, August 28, 2007). The E–Filing process requires participants to submit and serve all adjudicatory documents over the Internet, or in some cases to mail copies on electronic storage media. Participants may not submit paper copies of their filings unless they seek an exemption in accordance with the procedures described below.

To comply with the procedural requirements of E–Filing, at least ten (10) days prior to the filing deadline, the participant should contact the Office of the Secretary by e-mail at *hearing.docket@nrc.gov*, or by telephone at 301–415–1677, to request (1) a digital ID certificate, which allows the participant (or its counsel or representative) to digitally sign documents and access the E–Submittal server for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a request or petition for hearing (even in instances in which the participant, or its counsel or representative, already holds an NRC-issued digital ID certificate). Based upon this information, the Secretary will establish an electronic docket for the hearing in this proceeding if the Secretary has not already established an electronic docket.

Information about applying for a digital ID certificate is available on NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals/apply-certificates.html.* System requirements for accessing the E-Submittal server are detailed in NRC's ''Guidance for Electronic Submission,'' which is available on the agency's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* Participants may attempt to use other software not listed on the Web site, but should note that the NRC's E-Filing system does not support unlisted software, and the NRC Meta System Help Desk will not be able to offer assistance in using unlisted software.

If a participant is electronically submitting a document to the NRC in accordance with the E-Filing rule, the participant must file the document using the NRC's online, Web-based submission form. In order to serve documents through EIE, users will be required to install a Web browser plug-in from the NRC Web site. Further information on the Web-based submission form, including the installation of the Web browser plug-in, is available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.*

Once a participant has obtained a digital ID certificate and a docket has been created, the participant can then submit a request for hearing or petition for leave to intervene. Submissions should be in Portable Document Format (PDF) in accordance with NRC guidance available on the NRC public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* A filing is considered complete at the time the documents are submitted through the NRC's E-Filing system. To be timely, an electronic filing must be submitted to the E-Filing system no later than 11:59 p.m. Eastern Time on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an e-mail notice confirming receipt of the document. The E-Filing system also distributes an e-mail notice that provides access to the document to the NRC Office of the General Counsel and any others who have advised the Office of the Secretary that they wish to participate in the proceeding, so that the filer need not serve the documents on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before a hearing request/petition to intervene is filed so that they can obtain access to the document via the E-Filing system.

A person filing electronically using the agency's adjudicatory E-Filing system may seek assistance by contacting the NRC Meta System Help Desk through the ''Contact Us'' link located on the NRC Web site at *http://www.nrc.gov/site-help/e-submittals.html,* by e-mail at *MSHD.Resource@nrc.gov,* or by a toll-free call at (866) 672–7640. The NRC Meta System Help Desk is available between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday, excluding government holidays.

Participants who believe that they have a good cause for not submitting documents electronically must file an exemption request, in accordance with 10 CFR 2.302(g), with their initial paper filing requesting authorization to continue to submit documents in paper format. Such filings must be submitted by: (1) First class mail addressed to the Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemaking and Adjudications Staff; or (2) courier, express mail, or expedited delivery

[1] To the extent that the applications contain attachments and supporting documents that are not publicly available because they are asserted to contain safeguards or proprietary information, petitioners desiring access to this information should contact the applicant or applicant's counsel and discuss the need for a protective order.

service to the Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, Maryland, 20852, Attention: Rulemaking and Adjudications Staff. Participants filing a document in this manner are responsible for serving the document on all other participants. Filing is considered complete by first-class mail as of the time of deposit in the mail, or by courier, express mail, or expedited delivery service upon depositing the document with the provider of the service. A presiding officer, having granted an exemption request from using E-Filing, may require a participant or party to use E-Filing if the presiding officer subsequently determines that the reason for granting the exemption from use of E-Filing no longer exists.

Documents submitted in adjudicatory proceedings will appear in NRC's electronic hearing docket which is available to the public at *http://ehd1.nrc.gov/ehd/,* unless excluded pursuant to an order of the Commission, or the presiding officer. Participants are requested not to include personal privacy information, such as social security numbers, home addresses, or home phone numbers in their filings, unless an NRC regulation or other law requires submission of such information. With respect to copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, participants are requested not to include copyrighted materials in their submission.

Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc.,

Docket No. 50–271, Vermont Yankee Nuclear Power Station, Vernon, Vermont

Date of amendment request: September 29, 2011.

Description of amendment request: The amendment would revise the Technical Specifications to allow disarming either the supply breaker or the field breaker to the motor generator set for an idle recirculation pump when operating in single loop.

Date of issuance: September 30, 2011.

Effective date: As of the date of issuance, and shall be implemented within 30 days.

Amendment No.: 249.

Facility Operating License No. DPR–28: The amendment revised the License and the Technical Specifications.

Public Comments Requested as to Proposed No Significant Hazards Consideration (NSHC)

No. The Commission's related evaluation of the amendment, finding of emergency circumstances, and final determination of no significant hazards consideration are contained in a Safety Evaluation dated September 30, 2011.

Attorney for licensee: Mr. William C. Dennis, Assistant General Counsel, Entergy Nuclear Operations, Inc., 400 Hamilton Avenue, White Plains, NY 10601.

NRC Branch Chief: Nancy L. Salgado.

Dated at Rockville, Maryland this 6th day of October 2011.

For the Nuclear Regulatory Commission.

Michele Evans,

Director, Division of Operating Reactor Licensing, Office of Nuclear Reactor Regulation.

[FR Doc. 2011–26893 Filed 10–17–11; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards; Notice of Meeting

In accordance with the purposes of Sections 29 and 182b of the Atomic Energy Act (42 U.S.C. 2039, 2232b), the Advisory Committee on Reactor Safeguards (ACRS) will hold a meeting on November 3–5, 2011, 11545 Rockville Pike, Rockville, Maryland. The date of this meeting was previously published in the **Federal Register** on Thursday, October 21, 2010 (74 FR 65038–65039).

Thursday, November 3, 2011, Conference Room T2–B1, 11545 Rockville Pike, Rockville, Maryland

8:30 a.m.–8:35 a.m.: Opening Remarks by the ACRS Chairman (Open)—The ACRS Chairman will make opening remarks regarding the conduct of the meeting.

8:35 a.m.–10:30 a.m.: Nine Mile Point Unit 2 Extended Power Uprate Application (Open/Closed)—The Committee will hear presentations by and hold discussions with representatives of the NRC staff and Nine Mile Point Nuclear Station, LLC regarding the Nine Mile Point Unit 2 Extended Power Uprate Application. *Note:* A portion of this session may be closed in order to discuss and protect information designed as proprietary pursuant to 5 U.S.C. 552b(c)(4).

10:45 a.m.–12:45 p.m.: Branch Technical Position 7–19, ''Guidance for the Evaluation of Diversity and Defense-In-Depth in Digital Computer-Based Instrumentation and Control Systems'' (Open)—The Committee will hear presentations by and hold discussions with representatives of the NRC staff regarding Branch Technical Position 7–19, ''Guidance for the Evaluation of Diversity and Defense-In-Depth in Digital Computer-Based Instrumentation and Control Systems.''

1:45 p.m.–3:45 p.m.: Preparation for Meeting with the Commission (Open)—The Committee will discuss topics of interest in preparation for the Meeting with the Commission

4 p.m.–7 p.m.: Preparation of ACRS Reports (Open/Closed)—The Committee will discuss proposed ACRS reports on matters discussed during this meeting. The Committee will also discuss a proposed report on the prioritization of recommended actions to be taken in response to Fukushima lessons learned. *Note:* A portion of this session may be closed in order to discuss and protect information designed as proprietary pursuant to 5 U.S.C. 552b(c)(4).

Friday, November 4, 2011, Conference Room T2–B1, 11545 Rockville Pike, Rockville, Maryland

8:30 a.m.–8:35 a.m.: Opening Remarks by the ACRS Chairman (Open)—The ACRS Chairman will make opening remarks regarding the conduct of the meeting.

8:35 a.m.–10 a.m.: Future ACRS Activities/Report of the Planning and Procedures Subcommittee (Open/Closed)—The Committee will discuss the recommendations of the Planning and Procedures Subcommittee regarding items proposed for consideration by the Full Committee during future ACRS Meetings, and matters related to the conduct of ACRS business, including anticipated workload and member assignments. *Note:* A portion of this meeting may be closed pursuant to 5 U.S.C. 552b(c)(2) and (6) to discuss organizational and personnel matters that relate solely to internal personnel rules and practices of ACRS, and information the release of which would constitute a clearly unwarranted invasion of personal privacy.]

10 a.m.–10:15 a.m.: Reconciliation of ACRS Comments and Recommendations (Open)—The Committee will discuss the responses from the NRC Executive Director for Operations to comments and recommendations included in recent ACRS reports and letters.

10:30 a.m.–11:30 a.m.: Draft Report on the Biennial ACRS Review of the NRC Safety Research Program (Open)—The Committee will hold a discussion on the draft report on the biennial ACRS

review of the NRC Safety Research Program.

12:30 p.m.–7 p.m.: Preparation of ACRS Reports (Open/Closed)—The Committee will continue its discussion of proposed ACRS reports. *Note:* A portion of this session may be closed in order to discuss and protect information designed as proprietary pursuant to 5 U.S.C. 552b(c)(4).

Saturday, November 5, 2011 Conference Room T2–B1, 11545 Rockville Pike, Rockville, Maryland

8:30 a.m.–1 p.m.: Preparation of ACRS Reports (Open/Closed)—The Committee will continue its discussion of proposed ACRS reports. *Note:* A portion of this session may be closed in order to discuss and protect information designed as proprietary pursuant to 5 U.S.C. 552b(c)(4).

1 p.m.–1:30 p.m.: Miscellaneous (Open)—The Committee will continue its discussion related to the conduct of Committee activities and specific issues that were not completed during previous meetings.

Procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on October 21, 2010, (75 FR 65038–65039). In accordance with those procedures, oral or written views may be presented by members of the public, including representatives of the nuclear industry. Persons desiring to make oral statements should notify Ms. Ilka Berrios, Cognizant ACRS Staff (Telephone: 301–415–3179, E-mail: *Ilka.Berrios@nrc.gov*), five days before the meeting, if possible, so that appropriate arrangements can be made to allow necessary time during the meeting for such statements. In view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with the Cognizant ACRS staff if such rescheduling would result in major inconvenience.

Thirty-five hard copies of each presentation or handout should be provided 30 minutes before the meeting. In addition, one electronic copy of each presentation should be e-mailed to the Cognizant ACRS Staff one day before meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the Cognizant ACRS Staff with a CD containing each presentation at least 30 minutes before the meeting.

In accordance with Subsection 10(d) Public Law 92–463, and 5 U.S.C. 552b(c), certain portions of this meeting may be closed, as specifically noted above. Use of still, motion picture, and television cameras during the meeting may be limited to selected portions of the meeting as determined by the Chairman. Electronic recordings will be permitted only during the open portions of the meeting.

ACRS meeting agenda, meeting transcripts, and letter reports are available through the NRC Public Document Room at *pdr.resource@nrc.gov,* or by calling the PDR at 1–800–397–4209, or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS) which is accessible from the NRC Web site at *http://www.nrc.gov/reading-rm/adams.html* or *http://www.nrc.gov/reading-rm/doc-collections/ACRS/*.

Video teleconferencing service is available for observing open sessions of ACRS meetings. Those wishing to use this service for observing ACRS meetings should contact Mr. Theron Brown, ACRS Audio Visual Technician (301–415–8066), between 7:30 a.m. and 3:45 p.m. (ET), at least 10 days before the meeting to ensure the availability of this service.

Individuals or organizations requesting this service will be responsible for telephone line charges and for providing the equipment and facilities that they use to establish the video teleconferencing link. The availability of video teleconferencing services is not guaranteed.

If attending this meeting, please enter through the One White Flint North building, 11555 Rockville Pike, Rockville, MD. After registering with security, please contact Mr. Theron Brown (240–888–9835) to be escorted to the meeting room.

Dated: October 12, 2011.

Andrew L. Bates,

Advisory Committee Management Officer.

[FR Doc. 2011–26946 Filed 10–17–11; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Sunshine Federal Register Notice

AGENCY HOLDING THE MEETINGS: Nuclear Regulatory Commission, [NRC–2011–0006].

DATE: Weeks of October 17, 24, 31, November 7, 14, 21, 2011.

PLACE: Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland.

STATUS: Public and Closed.

Week of October 17, 2011

Tuesday, October 18, 2011

9 a.m. Briefing on Browns Ferry Unit 1 (Public Meeting). (Contact: Eugene Guthrie, 404–997–4662).

This meeting will be webcast live at the Web address—*http://www.nrc.gov.*

Thursday, October 20, 2011

1:30 p.m. NRC All Employees Meeting (Public Meeting). Marriott Bethesda North Hotel, 5701 Marinelli Road, Rockville, MD 20852.

Friday, October 21, 2011

9 a.m. Briefing on North Anna (Public Meeting). (Contact: Meena Khanna, 301–415–2150).

This meeting will be webcast live at the Web address— *http://www.nrc.gov.*

Week of October 24, 2011—Tentative

There are no meetings scheduled for the week of October 24, 2011.

Week of October 31, 2011—Tentative

Tuesday, November 1, 2011

9 a.m. Briefing on the Fuel Cycle Oversight Program (Public Meeting). (Contact: Margie Kotzalas, 301–492–3550).

This meeting will be webcast live at the Web address—*http://www.nrc.gov.*

Week of November 7, 2011—Tentative

There are no meetings scheduled for the week of November 7, 2011.

Week of November 14, 2011—Tentative

There are no meetings scheduled for the week of November 14, 2011.

Week of November 21, 2011—Tentative

There are no meetings scheduled for the week of November 21, 2011.

* The schedule for Commission meetings is subject to change on short notice. To verify the status of meetings, call (recording)—(301) 415–1292. Contact person for more information: Rochelle Bavol, (301) 415–1651.

The NRC Commission Meeting Schedule can be found on the Internet at: *http://www.nrc.gov/public-involve/public-meetings/schedule.html.*

The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in these public meetings, or need this meeting notice or the transcript or other information from the public meetings in another format (*e.g.* braille, large print), please notify Bill Dosch, Chief, Work Life and Benefits Branch, at 301–415–6200, TDD: 301–415–2100, or by e-mail at

william.dosch@nrc.gov. Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

This notice is distributed electronically to subscribers. If you no longer wish to receive it, or would like to be added to the distribution, please contact the Office of the Secretary, Washington, DC 20555 (301–415–1969), or send an e-mail to *darlene.wright@nrc.gov.*

Dated: October 13, 2011.

Rochelle Bavol,

Policy Coordinator, Office of the Secretary.

[FR Doc. 2011–27034 Filed 10–14–11; 4:15 pm]

BILLING CODE 7590–01–P

SECURITIES AND EXCHANGE COMMISSION

[Investment Company Act Release No. 29794; File No. 812–13855]

Curian Series Trust and Curian Capital, LLC; Notice of Application

September 19, 2011.

Correction

In notice document 2011–24590 appearing on pages 59455–59456 in the issue of September 26, 2011, make the following correction:

On page 59455, in the first column, the date, which was inadvertently omitted from the document heading, is added to read as set forth above.

[FR Doc. C1–2011–24590 Filed 10–17–11; 8:45 am]

BILLING CODE 1505–01–D

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65537; File No. SR–Phlx–2011–132]

Self-Regulatory Organizations; NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Modify the Minimum Quantity Order

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on September 30, 2011, NASDAQ OMX PHLX LLC (''PHLX'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by PHLX. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

PHLX is filing this proposed rule change to modify the operation of its Minimum Quantity Order in the NASDAQ OMX PSX (''PSX'') system. PHLX proposes to implement the rule change on a date that is at least thirty days after the date of the filing, but prior to November 30, 2011. The text of the proposed rule change is available at *http://nasdaqomxphlx.cchwallstreet.com/nasdaqomxphlx/phlx*, at PHLX's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

In order to provide enhanced functionality, PHLX is proposing to modify the functionality of its Minimum Quantity Order. Minimum Quantity Orders allow a market participant to specify a minimum share amount that the market participant seeks to obtain; accordingly, a Minimum Quantity Order will not execute unless the volume of liquidity available to execute against the order exceeds the designated minimum. A Minimum Quantity Order provides a means by which a market participant may avoid partial executions of orders at sizes that it considers inadequate to achieve its purposes. For example, a market participant seeking to sell a large position in a trading session with high volatility may use the order type to avoid selling only a small portion of the order at the price it considers acceptable.

Currently, Minimum Quantity Orders must be designated with a time-in-force of System Hours Immediate or Cancel or Market Hours Immediate or Cancel. As a result, the order can only be used to ''ping'' the PSX book to see if there is any posted liquidity that would allow the minimum execution. PHLX is proposing to remove this restriction so that a Minimum Quantity Order could post to the book if it cannot be executed immediately. Once posted, the order will execute if an incoming order that is marketable against it would satisfy its minimum quantity requirement. A Minimum Quantity Order that posts to the book is not displayed. Upon entry, all Minimum Quantity Orders must have a size, and a minimum quantity condition, of at least one round lot.

Under PSX's unique price-size order priority, Minimum Quantity orders at a particular price will be executed after (i) Displayed Orders and (ii) Non-Displayed Orders without a minimum quantity condition and the reserve portion of Reserve Orders (''Non-Displayed Interest'') with a size of at least on [sic] round lot. As among equally priced Minimum Quantity orders, incoming orders that satisfy the minimum quantity condition will be allocated among the resting orders in the ascending order of the size of their minimum quantity condition.[3]

Example: The book has four minimum quantity orders to buy at $10 with the following parameters:

O1: 300 shares, minimum quantity of 100 shares;
O2: 200 shares, minimum quantity of 200 shares;
O3: 500 shares, minimum quantity of 300 shares;
O4: 1000 shares, minimum quantity of 700 shares.

A marketable order to sell 600 shares is entered. 300 shares of the incoming order will be assigned to O1, and 200 shares will be assigned to O2. The remainder of the incoming order will skip O3 and O4 because their minimum quantity conditions cannot be satisfied.

In the event that the shares remaining in the size of a Minimum Quantity Order following a partial execution are less than the minimum quantity specified by the market participant entering the order, the minimum quantity value of the order will be reduced to the number of shares remaining. Thus, for example, if a market participant entered a Minimum Quantity Order with a size of 1,000 and a minimum quantity of 500, and the order was marketable against a 600 share order on the book, the remaining

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] If there are two or more Minimum Quantity Orders with an equal minimum quantity condition, the System will determine the order of execution on the basis of a random function that assigns each order an equal probability of execution.

400 shares of the Minimum Quantity Order would post to the book with a minimum quantity restriction of 400 shares. If the shares remaining in the size of a Minimum Quantity Order following a partial execution are less than one round lot, however, the minimum quantity restriction will no longer be effective.

2. Statutory Basis

PHLX believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[4] in general, and with Section 6(b)(5) of the Act,[5] in particular, in that the proposal is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Specifically, PHLX believes that the change to the functioning of the Minimum Quantity Order will provide market participants with better control over their trading patterns, thereby providing them with greater potential to improve the quality of their order executions.

B. Self-Regulatory Organization's Statement on Burden on Competition

PHLX does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended. The changes to the Minimum Quantity Order will enhance the functionality offered by PHLX to its members, thereby promoting its competitiveness with other exchanges and non-exchange trading venues that already offer similar functionality.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[6] and Rule 19b–l4(f)(6) thereunder.[7]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–Phlx–2011–132 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2011–132. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of PHLX. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–Phlx–2011–132 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[8]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26920 Filed 10–17–11; 8:45 am]

BILLING CODE 8011–01–P

[4] 15 U.S.C. 78f.

[5] 15 U.S.C. 78f(b)(5).

[6] 15 U.S.C. 78s(b)(3)(A).

[7] 17 CFR 240.19b–4(f)(6).

[8] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65379; File No. SR–CBOE–2011–079]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Adopt a Market-Maker Trade Prevention Order

September 22, 2011.

Correction

In notice document 2011–24866 appearing on pages 60108–60110 in the issue of September 28, 2011, make the following correction:

On page 60108, in the third column, the Release No. and File No., which were inadvertently omitted from the document heading, are added to read as set forth above.

[FR Doc. C1–2011–24866 Filed 10–17–11; 8:45 am]

BILLING CODE 1505–01–D

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65381; File No. SR–NASDAQ–2011–128]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Customer Rebates To Add Liquidity

September 22, 2011.

Correction

In notice document 2011–24868 appearing on pages 60103–60106 in the issue of September 28, 2011, make the following correction:

On page 60106, in the first column, in the first paragraph, in the last line, ''September 28, 2011'' should read ''October 19, 2011''.

[FR Doc. C1–2011–24868 Filed 10–17–11; 8:45 am]

BILLING CODE 1505–01–D

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65539; File No. SR–FICC–2011–07]

Self-Regulatory Organizations; The Fixed Income Clearing Corporation; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Make Technical Corrections to the Schedule of Timeframes, GCF Schedule of Timeframes, and Fee Structure in the GSD Rules

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] notice is hereby given that on September 30, 2011, the Fixed Income Clearing Corporation (''FICC'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change described in Items I and II below, which Items have been prepared primarily by FICC. FICC filed the proposal pursuant to Section 19(b)(3)(A)(ii) of the Act,[2] and Rule 19b–4(f)(2)[3] and Rule 19b–4(f)(4)[4] thereunder so that the proposal was effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the rule change from interested parties.

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78s(b)(3)(A)(ii).

[3] 17 CFR 240.19b–4(f)(2).

[4] 17 CFR 240.19b–4(f)(4).

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The proposed rule change will make technical corrections to the Schedule of Timeframes, GCF Schedule of Timeframes, and Fee Structure in the GSD Rules.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, FICC included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. FICC has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of these statements.[5]

(A) Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

The purpose of this filing is to make technical corrections to the Schedule of Timeframes, the GCF Schedule of Timeframes, and the Fee Structure as described below.

1. Schedule of Timeframes

The GSD Schedule of Timeframes is being updated to incorporate timeframes relating to the intraday collection of funds-only settlement and Clearing Fund amounts that were approved in connection with the SR–FICC–2010–09 rule filing.[6] The Schedule of Timeframes is also being revised to make certain other technical changes.

2. Schedule of GCF Timeframes

The Schedule of GCF Timeframes is being corrected to reflect that GCF Repo® trading is available to GCF brokers at 7 a.m.

3. Fee Structure Corrections

The following corrections are made to reflect fees that members are currently being charged:

Subsection A ''Trade Submission'' under ''Trade Comparison Fees'' currently describes trade submissions as including a submission of a side of a trade and a submission of a Repo Transaction. This is being corrected to make clear that Trade Submissions also include demand and bilateral submissions.

Subsection D ''Modifications and Cancellations'' under ''Trade Comparison Fees'' currently states that the charge to a Member for the entry of a request to modify or cancel a side of a GCF Repo Transaction is 5 cents per such request. This is being corrected to state that the charge is 5 cents per 50 million of par value.

The fee provided under Subsection E ''Demand and Locked-In Trade Data'' under ''Trade Comparison Fees'' currently states that fees for data received on a demand or locked-in basis related to a side of a trade or a Repo Transaction is 16 cents per 50 million increment. This is being corrected to state that this fee only applies to a Locked-In Trade Source related to a side of a trade, to clarify that the 50 million is of par value, and to delete the dollar sign ($) reference to par value.

Under ''Netting Fee and Charges,'' with respect to the ''Netting Fee'' (1) the references to ''par value'' incorrectly include a dollar sign ($); and (2) the Fail Deliver Obligation and Fail Receive Obligation currently states that the fee equals the sum of (i) $0.16 and (ii) $0.012 per $1 million of par value. This is being corrected to state that the fee equals the sum of (i) $0.18 and $0.018 per 1 million of par value. Under ''Auction Takedown Process'' of this same section, the fee in connection with locked in trades is clarified to state that the fee is $.50 per 50 million of par value increment.

FICC believes that the proposed rule change is consistent with the requirements of Section 17A of the Act[7] and the rules and regulations thereunder applicable to FICC because it facilitates the prompt and accurate clearance and settlement of securities by ensuring that FICC rules are consistent and accurate.

(B) Self-Regulatory Organization's Statement on Burden on Competition

FICC does not believe that the proposed rule change will have any impact or impose any burden on competition.

(C) Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments relating to the proposed rule change have not been solicited or received. FICC will notify the Commission of any written comments received by FICC.

[5] The Commission has modified the text of the summaries prepared by FICC.

[6] Securities Exchange Act Release No. 34–63986 (February 28, 2011), 76 FR 12144 (March 4, 2011).

[7] 15 U.S.C. 78q–1.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing proposed rule change has become effective upon filing pursuant to Section 19(b)(3)(A)(ii) of the Act,[8] and Rule 19b–4(f)(2)[9] and Rule 19b–4(f)(4)[10] thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov*. Please include File Number SR–FICC–2011–07 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FICC–2011–07. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filings also will be available for inspection and copying at the principal office of FICC and on FICC's Web site at *http://www.dtcc.com/downloads/legal/rule_filings/2011/ficc/2011-07-v2.pdf*. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–FICC–2011–07 and should be submitted on or before November 8, 2011.

For the Commission by the Division of Trading and Markets, pursuant to delegated authority.[11]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26888 Filed 10–17–11; 8:45 am]

BILLING CODE 8011–01–P

[8] 15 U.S.C. 78s(b)(3)(A)(ii).

[9] 17 CFR 240.19b–4(f)(2).

[10] 17 CFR 240.19b–4(f)(4).

[11] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65542; File No. SR–EDGA–2011–32]

Self-Regulatory Organizations; EDGA Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating To Amendments to the EDGA Exchange, Inc. Fee Schedule

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on September 30, 2011, the EDGA Exchange, Inc. (the ''Exchange'' or the ''EDGA'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its fees and rebates applicable to Members[3] of the Exchange pursuant to EDGA Rule 15.1(a) and (c). All of the changes described herein are applicable to EDGA Members. The text of the proposed rule change is available on the Exchange's Internet Web site at *http://www.directedge.com*.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in sections A, B and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

Purpose

The Exchange proposes to decrease its rebate from $0.0005 per share to $0.0004 per share for adding liquidity and increase its charge from $0.0006 per share to $0.0007 per share for removing liquidity. In the Exchange's fee schedule, these modifications are reflected in Flags B, V, Y, 3 and 4, where liquidity is added, and Flags N, W and 6, where liquidity is removed. The Exchange proposes to increase its charge for customer internalization in Flag E from $0.0001 per share, per side, to $0.00015 per share per side, to move in lockstep with the proposed maker/taker fee spread of $0.0003.

The Exchange proposes to add a new tier that provides if a Member, on a daily basis, measured monthly, posts more than 1% of the Total Consolidated Volume (''TCV'') in average daily volume, then the Member will receive a rebate of $0.0005 per share, which is reflected in the language in footnote 4. The Exchange proposes to add footnote 4 next to Flags B, V, Y, 3 and 4 to clarify that these flags count towards the tier.

The Exchange proposes to add the RR Flag for orders that are routed to the EDGX Exchange, Inc. (''EDGX'') and remove liquidity using routing strategies IOCX and IOCT, as defined in Exchange Rules Exchange Rules 11.9(b)(3)(l) and (m). The Exchange proposes to assess a charge of $0.0029 per share to account for the pass-through of the proposed EDGX fee for removing liquidity.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] A Member is any registered broker or dealer, or any person associated with a registered broker or dealer, that has been admitted to membership in the Exchange.

The Exchange proposes to decrease the charge assessed for removing liquidity for orders that are routed to the EDGX from $0.0030 per share to $0.0029 per share to reflect the reduction in EDGX's fee for removing liquidity. In the Exchange's fee schedule, this modification is reflected in the I Flag.

The Exchange proposes to eliminate the FIX (ECN Translator)[4] logical port fee effective as of October 1, 2011, as the ECN Translator is no longer being used by its Members and non-members.[5]

The Exchange also proposes to make technical amendments to the membership fee table included in the fee schedule to eliminate the word ''proposed'' since these fees were effective on September 1, 2011[6] and add the word ''will'' to footnote 3.

The Exchange proposes to implement these amendments to its fee schedule on October 1, 2011.

Basis

The Exchange believes that the proposed rule change is consistent with the objectives of Section 6 of the Act,[7] in general, and furthers the objectives of Section 6(b)(4),[8] in particular, as it is designed to provide for the equitable allocation of reasonable dues, fees and other charges among its members and other persons using its facilities.

The Exchange's proposal to decrease its rebate from $0.0005 per share to $0.0004 per share for adding liquidity and increase it charge from $0.0006 to $0.0007 per share for removing liquidity is designed to allow the Exchange to compete with other market centers. The Exchange believes the proposed maker/taker fee spread of $0.0002 or $0.0003, depending on if a tier is met (proposed footnote 4), is reasonable as the proposed maker/taker spread is competitive with other market centers maker/taker spreads (BATS BZX Exchange, 0–$0.0004 per share), Nasdaq OMX PSX ($.0001–$.0003 per share), and Nasdaq BX ($0.0001–$0.0013) [sic] per share). In addition, the Exchange proposes to increase its charge for customer internalization in Flag E from $0.0001 per share, per side, to $0.00015 per share per side, to move in lockstep with the proposed maker/taker fee spread of $0.0003. In addition, the increased revenue to the Exchange from the rate increase/decreased [sic] rebate would allow the Exchange to have additional revenue to offset administrative and infrastructure costs. The Exchange believes that the proposed rate is non-discriminatory in that it applies uniformly to all Members.

The Exchange's proposal to create a tier to provide an increased rebate of $0.0005 per share if Members post more than 1% of the TCV in average daily volume is designed to incentivize Members to route to EDGA and thereby, increase volume on EDGA. Such increased volume increases potential revenue to the Exchange, and would allow the Exchange to spread its administrative and infrastructure costs over a greater number of shares, leading to lower per share costs. These lower per share costs would allow the Exchange to pass on the savings to Members in the form of an increased rebate of $0.0005 per share. The increased liquidity also benefits all investors by deepening EDGA's liquidity pool, supporting the quality of price discovery, promoting market transparency and improving investor protection. Volume-based discounts such as the increase in rebate proposed herein have been widely adopted in the cash equities markets and provide discounts that are reasonably related to the value to an exchange's market quality associated with higher levels of market activity, such as higher levels of liquidity provision and introduction of higher volumes of orders into the price and volume discovery processes. The Exchange believes that the proposed increased rebate is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed charge associated with the RR flag ($0.0029 per share) represents an equitable allocation of reasonable dues, fees, and other charges since it reflects a pass through of the proposed EDGX fee for removing liquidity of $0.0029 per share. The RR Flag will only apply to orders incorporating routing strategies IOCX or IOCT, which are the Exchange's only two routing strategies that solely sweep EDGA and then route the balance of the order to EDGX. The RR Flag differs from the I Flag because the RR Flag is the result of two routing strategies that target EDGA, and the I Flag is the result of multiple routing strategies that execute at EDGA amongst other destinations. In addition, the Exchange believes the resulting effect of the RR Flag is consistent with similar strategies that solely target one other away exchange such as ROBA, ROBY and ROPA (and also pass on the removal rate of those respective exchange), pursuant to Exchange Rules 11.9(b)(3)(e), 11.9(b)(3)(g) and 11.9(b)(3)(k). EDGA believes that it is reasonable and equitable to pass on these fees to its members. The Exchange believes that the proposed charge is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed charge associated with the I flag ($0.0029 per share) represents an equitable allocation of reasonable dues, fees, and other charges since it reflects a pass through of the proposed EDGX fee for removing liquidity of $0.0029 per share. EDGA believes that it is reasonable and equitable to pass on these fees to its members. The Exchange believes that the proposed charge is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed elimination of the FIX (ECN Translator) logical port fee represents an equitable allocation of reasonable dues, fees, and other charges as the ECN Translator is no longer used by any Members and therefore, its elimination will not impact any Members. The proposed elimination of the fee also provides more simplicity to the fee schedule.

The Exchange also notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if they deem fee levels at a particular venue to be excessive. The proposed rule change reflects a competitive pricing structure designed to incent market participants to direct their order flow to the Exchange. The Exchange believes that the proposed rates are equitable and non-discriminatory in that they apply uniformly to all Members. The Exchange believes the fees and credits remain competitive with those charged by other venues and therefore continue to be reasonable and equitably allocated to Members.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any

[4] The ECN Translator allows a Member or non-member who previously connected to Direct Edge's ECN to be re-directed automatically to EDGA Exchange, Inc. It can only be accessed through a FIX port.

[5] Members were notified on May 3, 2011 that the ECN Translator ports would no longer be available as of August 1, 2011.

[6] *See* Securities Exchange Act Release No. 34–65188 (August 24, 2011), 76 FR 53988 (August 30, 2011) (SR–EDGA–2011–27).

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(4).

unsolicited written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3) [sic] of the Act [9] and Rule 19b–4(f)(2) [10] thereunder. At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an E-mail to *rule-comments@sec.gov*. Please include File Number SR–EDGA–2011–32 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–EDGA–2011–32. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–EDGA–2011–32 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26859 Filed 10–17–11; 8:45 am]

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[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 19b–4(f)(2).

[11] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65544; File No. SR–NYSEARCA–2011–69]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Adopting the Text of the FINRA Rule 7400 Series, the Order Audit Trail System (''OATS'') Rules, and Making Certain Conforming Changes

October 12, 2011.

Pursuant to Section 19(b)(1) [1] of the Securities Exchange Act of 1934 (the ''Act'') [2] and Rule 19b–4 thereunder,[3] notice is hereby given that, on October 7, 2011, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I and II, below, which Items have been prepared by the self-regulatory organization. The Exchange filed the proposal as a ''non-controversial'' proposed rule change pursuant to Section 19(b)(3)(A) of the Act [4] and Rule 19b–4(f)(6) [5] thereunder. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C.78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] 15 U.S.C. 78s(b)(3)(A).

[5] 17 CFR 240.19b-4(f)(6).

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to adopt the text of the FINRA Rule 7400 Series, the Order Audit Trail System (''OATS'') Rules, and make certain conforming changes. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *http://www.nyse.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to adopt the text of the FINRA Rules 7400 Series, the OATS Rules, and make certain conforming changes. The Exchange proposes this rule filing in order to harmonize its requirements with FINRA's requirements.[6]

Background

The Commission has recently approved amendments to the FINRA Rule 7400 Series to extend the OATS recording and reporting requirements to all NMS stocks and to exclude certain firms that have limited trading activities.[7] The FINRA Rule 7400 Series imposes obligations on FINRA members to record in electronic form and report to FINRA, on a daily basis, certain information with respect to orders originated, received, transmitted, modified, canceled, or executed by

[6] The Exchange's affiliates, New York Stock Exchange LLC (''NYSE'') and NYSE Amex LLC (''NYSE Amex''), are adopting substantially similar requirements. *See* SR–NYSE–2011–49 and SR–NYSEAmex–2011–74. As described below, the proposed rule change would also require ETP Holders that are not members of FINRA, which all meet the definition of a Proprietary Trading Firm in proposed Rule 7410(p), to also meet certain OATS requirements.

[7] *See* Securities Exchange Act Release No. 63311 (November 12, 2010), 75 FR 70757 (November 18, 2010) (SR–FINRA–2010–044) (''FINRA Adopting Release'').

members in OTC equity securities and equity securities listed and traded on NASDAQ. This information is used by FINRA staff to conduct surveillance and investigations of member firms for violations of FINRA rules and federal securities laws.

By extending the OATS requirements to all NMS stocks, all NYSE, NYSE Amex LLC, and NYSE Arca, Inc.-listed securities will become subject to the OATS requirement beginning October 17, 2011. As noted by FINRA in its rule proposal, by capturing OATS information for all NMS stocks, FINRA will be able to expand its existing surveillance patterns to conduct more comprehensive cross-market surveillance,[8] which is in furtherance of the Exchange's outsourcing of its surveillance and other regulatory functions to FINRA pursuant to a Regulatory Services Agreement.

The Exchange currently does not require its ETP Holders to maintain order information pursuant to an order tracking system. However, most ETP Holders are also FINRA members (''Dual Members'') and thus are currently subject to FINRA's OATS requirements.

Proposed Rule Change

Beginning October 17, 2011, Dual Members will become subject to the new FINRA OATS requirements by virtue of their status as FINRA members. Accordingly, by that date, Dual Members will need to update their existing OATS systems to accommodate all NMS stocks, including NYSE, NYSE Amex, and NYSE Arca-listed securities.[9] The Exchange proposes to harmonize its rules with the FINRA OATS requirements. In particular, the Exchange's proposal to adopt the OATS requirements will not require Dual Members to program their OATS systems any differently than they are already required to do so as a result of the FINRA OATS expansion. Moreover, because FINRA provides regulatory services on behalf of the Exchange, Dual Members would only need to report OATS information to FINRA once, both to meet the FINRA and proposed Exchange OATS requirements.

Some ETP Holders that are not members of FINRA are already members of NASDAQ, which has certain OATS obligations for proprietary trading firms under the NASDAQ Rule 6950 Series. The proposed OATS obligations for such ETP Holders are substantially similar to the existing NASDAQ OATS requirements for the same firms.

The Exchange proposes to adopt the text of the FINRA Rule 7400 Series as the NYSE Arca Equities Rule 7400 Series, with certain changes. The Exchange believes that by adopting the OATS rules, it will further promote cross-market surveillance and enhance FINRA's ability to conduct surveillance and investigations for the Exchange under the Regulatory Services Agreement.

The proposed NYSE Arca Equities Rule 7400 Series consists of NYSE Arca Equities Rules 7410 through 7470. Proposed NYSE Arca Equities Rule 7410 includes certain definitions to harmonize the NYSE Arca Equities Rule 7400 Series with the FINRA Rule 7400 Series. Proposed NYSE Arca Equities Rule 7410 will include all of the definitions of FINRA Rule 7410, with a few additions.[10] In particular, FINRA Rule 7410(g) and (m) cross reference NYSE rules for the definitions of index arbitrage and program trading. Because the NYSE will be deleting the rules that include those definitions, the Exchange proposes to include the text of those definitions, unchanged, in proposed NYSE Arca Equities Rule 7410(g) and (m). In addition, similar to NASDAQ Rule 6951(n), the Exchange proposes to add a definition of a proprietary trading firm in NYSE Arca Equities Rule 7410(p). Finally, for clarity, the Exchange proposes to add a definition of ''Exchange System,'' to mean the service provided by the Exchange that provides for the automated execution and reporting of transactions in NMS stocks.

Proposed NYSE Arca Equities Rule 7420 establishes the applicability of the rule to all ETP Holders and their associated persons [11] and all executed or unexecuted orders for all NMS stocks traded on the Exchange.

Proposed NYSE Arca Equities Rule 7430, which is substantially the same as FINRA Rule 7430, requires ETP Holders to synchronize and maintain their business clocks that are used for purposes of recording the date and time of any event that must be recorded pursuant to the NYSE Arca Equities rules with reference to a time source designated by the Exchange.

Proposed NYSE Arca Equities Rule 7440, which is based on Nasdaq Rule 6954, incorporates the FINRA Rule 7440 order data recording requirements. FINRA Rule 7440 requires members to record specified order information, including order origination and receipt information and order transmittal information, in a format specified by FINRA. Proposed NYSE Arca Equities Rule 7440 makes clear that pursuant to NYSE Arca Equities Rule 0 and the Exchange's Regulatory Services Agreement with FINRA, FINRA will capture order information on behalf of the Exchange and that FINRA Rules 7420 through 7460 will be construed as NYSE Arca Equities Rules 7420 through 7460 for compliance purposes. As such, complying with FINRA Rule 7440 and submitting OATS reports to FINRA will meet the requirements of proposed NYSE Arca Equities Rule 7440; Dual Members will not need to make separate submissions to the Exchange. Proposed NYSE Arca Equities Rule 7440 requires ETP Holders to assign and enter a unique order identifier to all orders that are electronically transmitted to the Exchange System. Dual Members already use such unique order identifiers when submitting orders to FINRA; thus, the proposed rule change would not impose new or different requirements than currently exist with respect to them.

As with proposed NYSE Arca Equities Rule 7440, proposed NYSE Arca Equities Rule 7450 requires ETP Holders to comply with the FINRA Rule 7450 order data transmission requirements as if FINRA Rule 7450 were part of the Exchange's rules. Accordingly, Dual Members who meet the FINRA order data submission requirements will also be meeting the Exchange order data transmission requirements. Similar to Nasdaq Rule 6955, proposed NYSE Arca Equities Rule 7450 will require Proprietary Trading Firms to comply with the order data transmission requirements only when they receive a request from the Exchange, i.e., FINRA, to submit order information.

Proposed NYSE Arca Equities Rule 7460, which is substantially the same as FINRA Rule 7460, states that a violation of the OATS Rules is a violation of NYSE Arca Equities Rule 2010.

Finally, proposed NYSE Arca Equities Rule 7470 establishes the exemptions to the order recording and data transmission requirements for manual

[8] *Id.* at 70758.

[9] FINRA has been actively working with all of its members, including Dual Members, to provide technical specifications for FINRA members to update their OATS systems to be compliant by the October 17, 2011 deadline. *See e.g., http://www.finra.org/Industry/Compliance/MarketTransparency/OATS/TechnicalSpecifications/.*

[10] The Exchange does not propose to adopt FINRA Rule 7410(o)(2) because the Exchange does not have any ETP Holders that were approved as a FINRA member pursuant to NASD IM–1013–1 or NASD IM–1013–2, which are NASD interpretive materials applicable to NYSE and NYSE Amex Floor-based member organizations only.

[11] The term ''Associated Person'' is defined in NYSE Arca Equities Rule 1.1(f) as a person who is a partner, officer, director, member of a limited liability company, trustee of a business trust, employee of an ETP Holder or any person directly or indirectly controlling, controlled by or under common control with an ETP Holder.

orders if the exemption is consistent with the protection of investors and the public interest, subject to certain criteria. The exemption is limited to a period of two years; however, subsequent exemptions may be requested. This proposed rule is also substantially the same as FINRA Rule 7470.

The Exchange proposes several technical changes to FINRA's OATS rule text. First, for consistency with Exchange rules, the Exchange proposes to (i) change all references from ''members'' to ''ETP Holders'' and from ''FINRA'' or ''NASDAQ'' to ''the Exchange,'' [12] respectively, (ii) add or modify the definitions for ''Exchange System,'' ''Proprietary Trading Firm,'' ''Index Arbitrage,'' and ''Program Trading,'' as described above and (iii) delete references to ''OTC equity security,'' which do [sic] not trade at the Exchange and thus is a moot reference. Second, rather than adopt the full text of FINRA Rules 7440 and 7450, which detail the recording of order information and order data transmission requirements, the Exchange modeled its proposed Rules 7440 and 7450 on NASDAQ's Rules 6954 and 6955, which instead cross-reference such requirements.[13] Third, consistent with a recent FINRA rule filing, the Exchange has adopted the July 10, 2015 extension date in NYSE Arca Equities Rule 7470.[14]

The Exchange proposes to implement the NYSE Arca Equities Rule 7400 Series at the same time that FINRA implements its Rule 7400 Series amendments with respect to Dual Members [15] and on January 31, 2012 with respect to ETP Holders that are not FINRA members. The Exchange proposes to give additional time to such ETP Holders because most of them have not been subject to OATS requirements in the past and may need additional time to program their systems in order to comply with the proposed rule change.

2. Statutory Basis

The proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (the ''Act''),[16] in general, and furthers the objectives of Section 6(b)(5),[17] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, and to remove impediments to and perfect the mechanism of a free and open market and a national market system. Specifically, the Exchange believes that the proposed rule change supports the objectives of the Act by providing greater harmonization between NYSE Arca Equities Rules and FINRA Rules. The changes that Dual Members will be required to make for the FINRA OATS requirements will meet the requirements of the Exchange's proposed adoption of OATS. The Exchange further believes that the proposed rule change will promote cross-market surveillance and enhance FINRA's ability to conduct surveillance and investigations for the Exchange under the Regulatory Services Agreement with respect to all ETP Holders, including non-FINRA members. To the extent the Exchange has proposed changes that differ from the FINRA version of the Rules, such changes are generally technical in nature and do not change the substance of the proposed NYSE Arca Equities Rules.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act [18] and Rule 19b–4(f)(6)(iii) [19] thereunder.

A proposed rule change filed under Rule 19b–4(f)(6) [20] normally does not become operative for 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),[21] the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has asked the Commission to waive the 30-day operative delay so that the proposal may become operative immediately upon filing.

The Commission is waiving the 30-day operative period.[22] The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the waiver will allow the Exchange's OATS requirements to be in place on the same date as the new FINRA OATS requirements. The Commission notes that the FINRA OATS requirements, which will be phased-in beginning October 17, 2011, would already apply to Dual Members.[23] Further, for the small number of ETP Holders that are not

[12] The Exchange notes that pursuant to NYSE Arca Equities Rule 0, references to the ''Exchange'' in its rules may also refer to FINRA. The Exchange will advise ETP Holders via an Information Memo whether a reference to the Exchange in the proposed Rule 7400 Series will require an ETP Holder to report directly to the Exchange or to FINRA on the Exchange's behalf. However, the Exchange anticipates that all OATS reporting will be submitted directly to FINRA, on behalf of the Exchange. To the extent that the Exchange or any of its facilities collect OATS data on behalf of ETP Holders, such information will be used for regulatory purposes only.

[13] *See* Securities Exchange Act Release No. 53128 (Jan. 13, 2006), 71 FR 3550 (Jan. 23, 2006) (File No. 10–131).

[14] *See* Securities Exchange Act Release No. 64717 (June 21, 2011), 76 FR 37384 (June 27, 2011) (SR–FINRA–2011–029).

[15] FINRA has announced that it will begin to phase-in the new recording and reporting requirements under its Rule 7400 Series beginning on October 17, 2011. *See* SR–FINRA–2011–055. FINRA also has announced that members may elect to report all NMS stocks beginning on October 17, 2011; however, only those securities required to be reported within each phase will be subject to all OATS matching processing, with all NMS stocks being reported by November 28, 2011. *See http://www.finra.org/Industry/Compliance/MarketTransparency/OATS/OATSReport/P124073*.

[16] 15 U.S.C. 78f(b).

[17] 15 U.S.C. 78f(b)(5).

[18] 15 U.S.C. 78s(b)(3)(A).

[19] 17 CFR 240.19b–4(f)(6)(iii). Rule 19b–4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time, as designated by the Commission. The Exchange has satisfied this requirement.

[20] 17 CFR 240.19b–4(f)(6).

[21] 17 CFR 240.19b–4(f)(6)(iii).

[22] For purposes only of waiving the operative delay of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[23] *See supra* note 15.

FINRA members, the Exchange has represented that they have received ample notice of the proposed change and will be given additional time, until January 31, 2012, to comply with the proposed rule change. Finally, the Commission notes that the proposed rule change is consistent with FINRA and Nasdaq rules previously approved by the Commission. The Commission, therefore, designates the proposed rule change to be operative upon filing with the Commission.

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NYSEARCA–2011–69 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEARCA–2011–69. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEARCA–2011–69 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[24]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26858 Filed 10–17–11; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65541; File No. SR–EDGX–2011–31]

Self-Regulatory Organizations; EDGX Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Amendments to the EDGX Exchange, Inc. Fee Schedule

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on September 30, 2011, the EDGX Exchange, Inc. (the ''Exchange'' or the ''EDGX'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its fees and rebates applicable to Members [3] of the Exchange pursuant to EDGX Rule 15.1(a) and (c). All of the changes described herein are applicable to EDGX Members. The text of the proposed rule change is available on the Exchange's Internet Web site at *http://www.directedge.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in sections A, B and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

Purpose

The Exchange proposes to decrease the charge assessed for removing liquidity fromthe Exchange from $0.0030 per share to $0.0029 per share. In the Exchange's feeschedule, these modifications are reflected in Flags N, W, 6 and PI, where liquidityis removed. The Exchange proposes adding footnote 12 to state that a removal rate of$0.0029 per share applies where an MPID's add liquidity ratio is equal to or greaterthan 10%. The add liquidity ratio is defined as ''added'' flags/(''added'' flags + ''removal'' flags) × 100, where added flags includeB, H, V, Y, MM, 3, or 4 and removal flags include MT, N, W, PI, or 6. The removalrate of $0.0029 per share applies to single MPIDs only as share volume calculationsfor wholly owned affiliates cannot be aggregated across multiple MPIDs on aprospective basis. The Exchange also proposes to add language to state that theremoval rate of $0.0030 per share will apply where a Member does not meet the addliquidity ratio of at least 10%.

The Exchange proposes to add the RR Flag for orders that are routed to the EDGA Exchange and remove liquidity using routing strategies IOCX and IOCT, as defined in Exchange Rules 11.9(b)(3)(l) and (m). The Exchange proposes to assess a charge of $0.0007 per share to account for the pass-through of the proposed EDGA fee for removing liquidity.

The Exchange proposes to add the PI Flag to the fee schedule for orders that

[24] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] A Member is any registered broker or dealer, or any person associated with a registered broker or dealer, that has been admitted to membership in the Exchange.

remove liquidity from the EDGX Exchange against the Midpoint Match, as defined in Exchange Rule 11.5(c)(7). The Exchange proposes to assess a charge of $0.0029 per share, which corresponds to the proposed fee of $0.0029 per share assessed for removing liquidity from the Exchange.

The Exchange proposes to incorporate the H Flag for Non-Displayed Orders that add liquidity, as defined in Exchange Rule 11.5(c)(8), but not including Midpoint Match Orders. The Exchange proposes to provide a rebate of $0.0015 per share.

The Exchange proposes to eliminate the FIX (ECN Translator)[4] logical port fee effective as of October 1, 2011, as the ECN Translator is no longer being used by its Members and non-members.[5]

The Exchange proposes to make technical amendments to Flags MM and MT to add ''using Midpoint Match order type'' to further clarify the order types where the fees will be assessed.

The Exchange proposes to make a technical amendment to footnote 9 by adding ''per share'' to clarify that the fee will be calculated on a per share basis.

The Exchange also proposes to make technical amendments to the membership fee table included in the fee schedule to eliminate the word ''proposed'' since these fees were effective on September 1, 2011[6] and add the word ''will'' to footnote 3.

The Exchange proposes to implement these amendments to its fee schedule on October 1, 2011.

Basis

The Exchange believes that the proposed rule changes are consistent with the objectives of Section 6 of the Exchange Act,[7] in general, and furthers the objectives of Section 6(b)(4),[8] in particular, as it is designed to provide for the equitable allocation of reasonable dues, fees and other charges among its members and other persons using its facilities.

The Exchange believes that the proposed decrease in rate for removing liquidity from $0.0030 per share to $0.0029 per share provided that a certain add liquidity ratio is met by Members (and the conforming flag changes to flags N, W, 6, and PI) represents an equitable allocation of reasonable dues, fees, and other charges. The Exchange believes that this decreased fee to Members would incent further liquidity to the Exchange and provide an incentive for Members to provide liquidity that supports the quality of price discovery and promotes market transparency. The tier rewards Members who provide liquidity to the Exchange (at least a 10% add liquidity ratio), and provides a decreased fee that is reasonably related to the value to the exchange's market quality associated with higher volumes. Such similar ratios are also used by NYSE Arca.[9] Such increased volume also increases potential revenue to the Exchange, and would allow the Exchange to spread its administrative and infrastructure costs over a greater number of shares, leading to lower per share costs. These lower per share costs would allow the Exchange to pass on the savings to Members in the form of a lower fee. The Exchange believes that the proposed rate is non-discriminatory in that it applies uniformly to all Members.

In addition, the Exchange proposes to apply a removal rate of $0.0029 per share to single MPIDs only, which is consistent with the precedent set forth by NASDAQ in its fee schedule, where it gives different rates for liquidity ''added through any single MPID'' versus liquidity ''added by firms'' as whole.[10] The Exchange believes this competitive pricing promotes increased liquidity provision to EDGX by each individual MPID, which supports the quality of price discovery and promotes market transparency. At this time, the Exchange approximates that more than 250 MPIDs will qualify for this reduced rate. In footnote 12 of the fee schedule, the Exchange states that a removal rate of $0.0029 per share cannot be aggregated across multiple MPIDs on a prospective basis because the Exchange does not want to incidentally reward MPID(s) that do not contribute to this liquidity provision. The Exchange believes that the proposed rate is non-discriminatory in that it applies uniformly to all Members and MPIDs.

The Exchange believes that the proposed fee for the PI flag of $0.0029 per share represents an equitable allocation of reasonable dues, fees, and other charges since the fee is in line with standard rate for removal of liquidity from the Exchange of $0.0029 per share.[11] The PI flag will increase transparency for Members as well as enable them to track their orders that execute against the Midpoint Match and result in price improvement. The Exchange also believes that the PI Flag will afford the Exchange the flexibility to offer additional cost savings and/or price discounts for orders that offer price improvements in the future. Similarly, the Exchange believes that the proposed rate is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed charge associated with the RR flag ($0.0007 per share) represents an equitable allocation of reasonable dues, fees, and other charges since it reflects a pass through of the proposed EDGA fee for removing liquidity of $0.0007 per share. The RR Flag will only apply to orders incorporating routing strategies IOCX or IOCT, which are the Exchange's only two routing strategies that solely sweep EDGX and then route the balance of the order to EDGA. The RR Flag differs from the I Flag because the RR Flag is the result of two routing strategies that target EDGA, and the I Flag is the result of multiple routing strategies that execute at EDGA amongst other destinations. In addition, the Exchange believes the resulting effect of the RR Flag is consistent with similar strategies that solely target one other away exchange such as ROBA, ROBY and ROPA (and also pass on the removal rate of those respective exchange), pursuant to Exchange Rules 11.9(b)(3)(e), 11.9(b)(3)(g) and 11.9(b)(3)(k). In addition, EDGX believes that it is reasonable and equitable to pass on these fees to its members. The Exchange believes that the proposed charge is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed rebate of $0.0015 per share for adding non-displayed orders to the EDGX book represents an equitable allocation of reasonable dues, fees, and other charges as it is designed to incentivize Members to add hidden liquidity to the book, but not reward them as much as those who offer displayed liquidity (standard rebate of $0.0023 per share). The Exchange implemented the H Flag in order to differentiate between the relative value (and rebates) of non-displayed orders and displayed orders. In addition, the rate is [sic] line with other similar

[4] The ECN Translator allows a Member or non-member who previously connected to Direct Edge's ECN to be re-directed automatically to EDGX Exchange, Inc. It can only be accessed through a FIX port.

[5] Members were notified on May 3, 2011 that the ECN Translator ports would no longer be available as of August 1, 2011.

[6] *See* Securities Exchange Act Release No. 34–65189 (August 24, 2011), 76 FR 53990 (August 30, 2011) (SR–EDGX–2011–26).

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(4).

[9] *See* Securities Exchange Act Release No. 64593 (June 3, 2011), 76 FR 33380 (June 8, 2011) (SR–NYSEArca–2011–34) (introducing Investor Tier 1 and Investor Tier 2).

[10] *See http://www.nasdaqtrader.com/Trader.aspx?id=PriceListTrading2.*

[11] The Exchange notes that the PI flag is to be contrasted with the MT flag in that the PI flag results from an incidental match against Midpoint Match, while the MT flag results from a Member intentionally sending order flow through Midpoint Match.

exchange rebates offered for hidden liquidity by BATS (rebate of $0.0017 per share), Nasdsaq tiered rate of .0010/.0015), and NYSE Arca (rebate of $0.0015 per share). The Exchange believes that the proposed rebate is non-discriminatory in that it applies uniformly to all Members.

The Exchange believes that the proposed elimination of the FIX (ECN Translator) logical port fee represents an equitable allocation of reasonable dues, fees, and other charges as the ECN Translator is no longer used by any Members and therefore, its elimination will not impact any Members. The proposed elimination of the fee also provides more simplicity to the fee schedule.

The Exchange notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if they deem fee levels at a particular venue to be excessive. The proposed rule changes reflect a competitive pricing structure designed to incent market participants to direct their order flow to the Exchange. The Exchange believes that the proposed rates are non-discriminatory in that they apply uniformly to all Members. The Exchange believes the fees and credits remain competitive with those charged by other venues and therefore continue to be reasonable and equitably allocated to Members.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3) [sic] of the Act [12] and Rule 19b–4(f)(2) [13] thereunder. At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- *Use the Commission's Internet comment form (http://www.sec.gov/rules/sro.shtml*); or
- Send an E-mail to *rule-comments@sec.gov.* Please include File Number SR–EDGX–2011–31 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–EDGX–2011–31 This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–EDGX–2011–31 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26857 Filed 10–17–11; 8:45 am]

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[12] 15 U.S.C. 78s(b)(3)(A).

[13] 17 CFR 19b–4(f)(2).

[14] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65536; File No. SR–NASDAQ–2011–140]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Modify the Minimum Quantity Order

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on September 30, 2011, The NASDAQ Stock Market LLC (''NASDAQ'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by NASDAQ. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

NASDAQ is filing this proposed rule change to modify the operation of its Minimum Quantity Order. NASDAQ proposes to implement the rule change on a date that is at least thirty days after the date of the filing, but prior to November 30, 2011. The text of the proposed rule change is available at *http://nasdaq.cchwallstreet.com/,* at NASDAQ's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in Sections A, B, and C below, of

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

In order to provide enhanced functionality, NASDAQ is proposing to modify the functionality of its Minimum Quantity Order. Minimum Quantity Orders allow a market participant to specify a minimum share amount that the market participant seeks to obtain; accordingly, a Minimum Quantity Order will not execute unless the volume of liquidity available to execute against the order exceeds the designated minimum. A Minimum Quantity Order provides a means by which a market participant may avoid partial executions of orders at sizes that it considers inadequate to achieve its purposes. For example, a market participant seeking to sell a large position in a trading session with high volatility may use the order type to avoid selling only a small portion of the order at the price it considers acceptable.

Currently, Minimum Quantity Orders must be designated with a time-in-force of System Hours Immediate or Cancel or Market Hours Immediate or Cancel. As a result, the order can only be used to ''ping'' the NASDAQ book to see if there is any posted liquidity that would allow the minimum execution. NASDAQ is proposing to remove this restriction so that a Minimum Quantity Order could post to the book if it cannot be executed immediately. Once posted, the order will execute if an incoming order that is marketable against it would satisfy its minimum quantity requirement. A Minimum Quantity Order that posts to the book is not displayed. Upon entry, a Minimum Quantity Order must have a size and a minimum quantity condition of at least one round lot.

In the event that the shares remaining in the size of a Minimum Quantity Order following a partial execution are less than the minimum quantity specified by the market participant entering the order, the minimum quantity value of the order will be reduced to the number of shares remaining. Thus, for example, if a market participant entered a Minimum Quantity Order with a size of 1,000 and a minimum quantity of 500, and the order was marketable against a 600 share order on the book, the remaining 400 shares of the Minimum Quantity Order would post to the book with a minimum quantity restriction of 400 shares.

2. Statutory Basis

NASDAQ believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[3] in general, and with Section 6(b)(5) of the Act,[4] in particular, in that the proposal is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Specifically, NASDAQ believes that the change to the functioning of the Minimum Quantity Order will provide market participants with better control over their trading patterns, thereby providing them with greater potential to improve the quality of their order executions.

B. Self-Regulatory Organization's Statement on Burden on Competition

NASDAQ does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended. The changes to the Minimum Quantity Order will enhance the functionality offered by NASDAQ to its members, thereby promoting its competitiveness with other exchanges and non-exchange trading venues that already offer similar functionality.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[5] and Rule 19b–4(f)(6) thereunder.[6]

[3] 15 U.S.C. 78f.

[4] 15 U.S.C. 78f(b)(5).

[5] 15 U.S.C. 78s(b)(3)(A).

[6] 17 CFR 240.19b–4(f)(6).

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–NASDAQ–2011–140 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2011–140. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of NASDAQ. All comments received will

be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2011–140 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[7]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26856 Filed 10–17–11; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65538; File No. SR–BX–2011–070]

Self-Regulatory Organizations; NASDAQ OMX BX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the BOX Fee Schedule

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on October 5, 2011, NASDAQ OMX BX, Inc. (the ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Exchange filed the proposed rule change pursuant to Section 19(b)(3)(A)(ii) of the Act,[3] and Rule 19b–4(f)(2) thereunder,[4] which renders the proposal effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the proposed rule from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

NASDAQ OMX BX, Inc. (the ''Exchange'') proposes to amend the Fee Schedule of the Boston Options Exchange Group, LLC (''BOX''). Changes to the BOX Fee Schedule pursuant to this proposal will be effective upon filing. The text of the proposed rule change is available from the principal office of the Exchange, at the Commission's Public Reference Room and also on the Exchange's Internet Web site at *http://nasdaqomxbx.cchwallstreet.com/NASDAQOMXBX/Filings/.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

As set forth in greater detail below, the Exchange proposes several changes to the BOX Fee Schedule to reflect the implementation of fees for Professional[5] accounts, and for the BOX Solicitation Auction and Facilitation Auction mechanisms.[6]

Section 1 Trading Fees for Public Customer Accounts

Currently, the trading fee for Public Customers in Section 1a of the BOX Fee Schedule is $0.15 per executed contract of an Improvement Order for a Public Customer that is not submitted as a Customer Price Improvement Period Order for the Price Improvement Period (''non-CPO'' in the ''PIP'').[7] The Exchange proposes to add to Section 1a the same $0.15 fee per executed contract for Responses in the Solicitation and Facilitation Auction mechanisms.

Additionally, the fee in Section 1b is $0.25 per executed contract for Primary Improvement Orders for a Public Customer. The Exchange proposes to add to Section 1b a $0.25 fee per executed contract for Facilitation Orders and Solicitation Orders for Public Customers.

Currently, the fee for Public Customers in Section 1c is $0.07 per executed contract for all non-PIP transactions. The Exchange proposes to amend Section 1c to expand this applicable fee to all non-Auction Transactions and define the term ''Auction Transactions'' to include all transactions executed through PIP, the Solicitation Auction mechanism, and the Facilitation Auction mechanism.

Section 2 Trading Fees for Professional Accounts

The Exchange proposes to add the Trading Fees For Professional Accounts as Section 2 of the BOX Fee Schedule and renumber the Trading Fees For Broker Dealer Proprietary Accounts as Section 3 and Market Maker Trading Fees as Section 4.

The Exchange proposes that Professional accounts pay the same fees as set forth for Public Customers in Section 1 of the Fee Schedule for all Auction Transactions. The Exchange also proposes that Professional accounts pay $0.20 per executed contract for all non-Auction Transactions.[8]

The Exchange also proposes to add Professional to the account types listed in Section 7a of the Fee Schedule that specifies the Fees for Adding Liquidity and Credits for Removing Liquidity in transactions on the BOX Book (non-Auction Transactions). These Fees and Credits for non-Auction Transactions are the same across all account types, now proposed to include Professional accounts, and the Exchange is not proposing any change to these Fees and Credits at this time.

Section 3 Broker Dealer Fees and Section 4 Market Maker Fees

The Exchange proposes to amend the Fee Schedule to correspond with the proposed change in Section 1c of the Fee Schedule to change references to PIP transactions to Auction Transactions so as to include transactions in the Solicitation and Facilitation Auction mechanisms. Additionally, the Exchange proposes that broker-dealers and market makers pay the same fees for non-Auction Transactions as they currently pay for non-PIP transactions. No change to

[7] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(ii).

[4] 17 CFR 240.19b–4(f)(2).

[5] *See* Securities Exchange Act Release No. 65036 (August 4, 2011) 76 FR 49517 (August 10, 2011) (SR–BX–2011–049) (Notice of Filing and Immediate Effectiveness To Adopt a Definition of ''Professional'' and Require That Professional Orders Be Appropriately Marked by BOX Options Participants). *See also* BOX Trading Rules Chapter I, Section 1(a)(52). The term ''Professional'' means any person or entity that (i) is not a broker or dealer in securities, and (ii) places more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s).

[6] *See* Securities Exchange Act Release No. 65387 (September 23, 2011) (SR–BX–2011–034) (Order Approving Amending the BOX Trading Rules to Establish Facilitation and Solicitation Auction Mechanisms).

[7] *See* Price Improvement Period (''PIP'') in Chapter V, Section 18 of the BOX Trading Rules.

[8] By comparison to Professional accounts, Trading Fees for non-Auction Transactions are $0.07 per executed contract for Public Customers and $0.40 per executed contract for Broker-Dealer Proprietary Accounts.

these fees is proposed. Further, the Exchange proposes to amend Sections 7a, 7b, and 7d to change references to the transaction fees in certain sections of the Fee Schedule to correspond to the renumbered Sections 3 and 4 of the Fee Schedule, as outlined above.

Section 7e Transactions in BOX Facilitation and Solicitation Auction

The Exchange proposes to add Section 7e to the Fee Schedule to implement Fees for Adding Liquidity and Credits for Removing Liquidity in the BOX Facilitation and Solicitation Auction mechanisms. The fees and credits in Section 7e shall be applied to transactions in these respective mechanisms, in addition to applicable transaction fees as described in Section 1 through 4 of the proposed Fee Schedule. Agency Orders submitted in Facilitation or Solicitation will receive the 'removal' credit. Facilitation Orders, Solicited Orders, or Responses, respectively, will be charged the 'add' fee per executed contract. The Exchange proposes that the Fee for Adding Liquidity and the Credit for Removing Liquidity be $0.30 per contract for all classes in these respective auction mechanisms, and be assessed the same across all account types: Market Maker, Firm, Public Customer, and Professional.

Section 7f Tiered Fee for Initiating Participants Based Upon Average Daily Volume (ADV) of BOX Auction Transactions

Currently, Section 7d of the Fee Schedule provides for a tiered fee to be applied for PIP transactions by Initiating Participants. Greater ADV in PIP transactions results in a reduced PIP transaction fee. The Exchange proposes to amend this tiered fee so as to apply all of an Initiating Participant's Auction Transactions (including transactions in the Facilitation and Solicitation Auctions, not just those in the PIP) to the calculation of the Initiating Participant's ADV to determine the transaction fee applicable to the Participant. The Exchange also proposes to renumber this tiered fee provision as new Section 7f. No changes to the ADV or tiered fee rates are proposed.

Section 8 Eligible Orders Routed to an Away Exchange

Finally, the Exchange proposes to amend Section 8 of the BOX Fee Schedule to delete its current routing fees and adopt a $0.50 per contract routing fee for Professional accounts.[9] The Exchange proposes this routing fee, in part to offset the various costs BOX incurs in providing routing services. BOX uses third-party broker-dealers to route orders to other exchanges and incurs charges for each order routed to an away market.

2. Statutory Basis

The Exchange believes that the proposal is consistent with the requirements of Section 6(b) of the Act,[10] in general, and Section 6(b)(4) of the Act,[11] in particular, in that it provides for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities. The Exchange believes the proposal is an equitable allocation of reasonable fees, credits, and other charges among BOX Options Participants. The proposed changes will allow the fees charged on BOX to remain competitive with other exchanges as well as apply such fees in a manner which is equitable among all BOX Participants. The Exchange believes the proposed transaction fees and credits are fair and reasonable and must be competitive with fees and credits in place on other exchanges. Further, the Exchange believes that this competitive marketplace impacts the fees and credits present on BOX today and influences this proposal.

Auction Mechanism Fees

The Exchange believes it is equitable and non-discriminatory to assess the proposed fees for the BOX Solicitation and Facilitation Auction mechanisms because the proposed fee for adding liquidity and credit for removing liquidity will apply uniformly to all categories of participants, across all account types, now proposed to include Professional accounts. The Exchange also believes the proposed fees for the BOX auction mechanisms to be reasonable. BOX operates within a highly competitive market in which market participants can readily direct order flow to any of eight other competing venues if they deem fees at a particular venue to be excessive. The fee structure proposed for these auction mechanisms, in particular, the proposed credit for removing liquidity, aims to attract additional order flow to these BOX auction mechanisms, providing greater potential liquidity within the overall BOX market to the benefit of all BOX market participants.

The Exchange believes it is equitable and non-discriminatory to provide Initiating Participants a tiered fee structure related to its participation in BOX Auction Transactions. The proposed fee structure related to trading activity in BOX Auction Transactions is available to all BOX Options Participants and they may choose to trade on BOX to take advantage of the discounted fees for doing so, or not. The Exchange also believes the proposed fees for the BOX auction mechanisms to be reasonable. BOX has had this same tiered fee structure in place related to PIP transactions by Initiating Participants. Participants will benefit from the opportunity to now aggregate their trading in the BOX Facilitation and Solicitation Auction mechanisms with their PIP transactions to more easily attain a discounted fee tier. As noted above, BOX operates within a highly competitive market in which market participants can readily direct order flow to any of eight other competing venues if they deem fees at a particular venue to be excessive. The tiered fee structure proposed for trading in the BOX auction mechanisms aims to attract additional order flow to BOX, providing greater potential liquidity within the overall BOX market, its auction mechanisms, to the benefit of all BOX market participants.

Trading Fees for Professional Accounts

The Exchange believes it is equitable and non-discriminatory to assess fees for Professional accounts that are the same in the Facilitation and Solicitation Auction Transactions as those fees for Public Customers. Also, as stated above, the Exchange believes it is equitable, reasonable, and non-discriminatory to assess Professional accounts the same liquidity related fees or credits, as those paid to or paid by Public Customers, Broker-Dealer Proprietary Trading accounts and Market Makers. Within these Auction Transactions, Professionals retain priority as Public Customer orders, and the Exchange believes that such orders benefit from the BOX fees and credits as structured within Auction Transactions. The proposed fees for Professional accounts for adding liquidity and credit for removing liquidity are equitable and non-discriminatory because such fees and credits apply uniformly to all categories of participants and across all account types.

Further, the Exchange believes the proposed $0.20 fee per executed contract for Professional accounts in non-Auction Transactions to be equitable, reasonable, and not unfairly discriminatory. As stated, BOX operates

[9] By comparison, BOX does not route broker-dealer proprietary orders and thus does not assess them any routing fees. Additionally, BOX routes Public Customer orders to Away Exchanges at no charge.

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(4).

within a highly competitive market. BOX, however, does not assess ongoing systems access fees, ongoing fees for access to BOX market data, or fees related to order cancellation. Professional accounts, while Public Customers by virtue of not being broker-dealers, generally engage in trading activity more similar to broker-dealer proprietary trading accounts (more than 390 orders per day on average). This level of trading activity draws on a greater amount of BOX system resources than that of non-Professional Public Customers. Simply, the more orders submitted to BOX, the more messages sent to and received from BOX, the more orders potentially routed to away exchanges, and the more BOX system resources utilized. This level of trading activity by Professional accounts results in greater ongoing operational costs to BOX. As such, BOX aims to recover its costs by assessing Professional accounts the same fees that it assesses to other BOX market participants in Facilitation and Solicitation Auction Transactions, and a market competitive fee proposed for non-Auction Transactions. Generally, competing options exchanges assess Professionals fees at rates more comparable to fees charged to broker-dealers. Sending orders to and trading on BOX are entirely voluntary. Under these circumstances, BOX transaction fees must be competitive to attract order flow, execute orders, and grow its market. As such, BOX believes its trading fees proposed for Professional accounts are fair and reasonable. While comparably higher transaction fees than those assessed to Public Customers, BOX is assessing Professional accounts transaction fees at a rate ($0.20) lower than that charged to broker-dealer proprietary trading firms.

Moreover, the Exchange believes it is equitable and not unfairly discriminatory to charge Public Customers lower fees for non-Auction Transactions than Professional accounts that are more akin to Broker-Dealer Proprietary Trading Accounts. The securities markets generally, and BOX in particular, have historically aimed to improve markets for investors and develop various features within the market structure for customer benefit. As such, the Exchange believes the proposed non-Auction Transaction fees for Professional accounts, as compared to Public Customer transaction fees, is appropriate and not unfairly discriminatory.

Finally, the Exchange believes that the proposed change to adopt a fee for routing Professional customer orders to various markets is reasonable, equitable, and not unfairly discriminatory in that the fee will allow BOX to recoup its costs attendant with offering optional routing services. BOX uses third-party broker-dealers to route orders to other exchanges and incurs charges for each order routed to an away market, in addition to the fees charged by other exchanges. BOX does not route broker-dealer proprietary orders, and therefore, does not assess routing fees on such orders, and has generally been providing its routing services to Public Customers at a deeply discounted fee. BOX incurs various costs related to providing routing services. In order to better recover those related costs and to potentially generate additional revenue, the Exchange proposes a routing fee to provide this optional service to Professional accounts.

The Exchange also notes that although routing is available to BOX Participants for customer orders, including Professionals, BOX Participants are not required to use the routing services. Rather, BOX routing services are completely optional. BOX Participants can manage their own routing to different options exchanges or can utilize a myriad of other routing solutions that are available to market participants. Further, as noted above, the characteristics of Professional accounts tend to be more similar to broker-dealers than to non-Professional Public Customers. As such, BOX believes Professionals are more likely to be able to route their orders to the exchange venues where they wish to trade. By assessing a fee on Professional accounts for routing orders, BOX aims to recover its costs in providing this optional service to its Participants and their Professional customer accounts. The Exchange believes that providing Public Customers a preferred rate for routing is consistent with the long history in the options markets of such customers being given preferred fees.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act[12] and Rule 19b–4(f)(2) thereunder,[13] because it establishes or changes a due, fee, or other charge applicable only to a member.

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend the rule change if it appears to the Commission that the action is necessary or appropriate in the public interest, for the protection of investors, or would otherwise further the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–BX–2011–070 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BX–2011–070. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and

[12] 15 U.S.C. 78s(b)(3)(A)(ii).

[13] 17 CFR 240.19b–4(f)(2).

printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BX–2011–070 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26855 Filed 10–17–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65535; File No. SR–BX–2011–069]

Self-Regulatory Organizations; NASDAQ OMX BX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Modify the Minimum Quantity Order

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on September 30, 2011, NASDAQ OMX BX, Inc. (''BX'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by BX. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

BX is filing this proposed rule change to modify the operation of its Minimum Quantity Order. BX proposes to implement the rule change on a date that is at least thirty days after the date of the filing, but prior to November 30, 2011. The text of the proposed rule change is available at *http://nasdaqomxbx.cchwallstreet.com*, at BX's principal office, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

In order to provide enhanced functionality, BX is proposing to modify the functionality of its Minimum Quantity Order. Minimum Quantity Orders allow a market participant to specify a minimum share amount that the market participant seeks to obtain; accordingly, a Minimum Quantity Order will not execute unless the volume of liquidity available to execute against the order exceeds the designated minimum. A Minimum Quantity Order provides a means by which a market participant may avoid partial executions of orders at sizes that it considers inadequate to achieve its purposes. For example, a market participant seeking to sell a large position in a trading session with high volatility may use the order type to avoid selling only a small portion of the order at the price it considers acceptable.

Currently, Minimum Quantity Orders must be designated with a time-in-force of System Hours Immediate or Cancel or Market Hours Immediate or Cancel. As a result, the order can only be used to ''ping'' the BX book to see if there is any posted liquidity that would allow the minimum execution. BX is proposing to remove this restriction so that a Minimum Quantity Order could post to the book if it cannot be executed immediately. Once posted, the order will execute if an incoming order that is marketable against it would satisfy its minimum quantity requirement. A Minimum Quantity Order that posts to the book is not displayed. Upon entry, a Minimum Quantity Order must have a size and a minimum quantity condition of at least one round lot.

In the event that the shares remaining in the size of a Minimum Quantity Order following a partial execution are less than the minimum quantity specified by the market participant entering the order, the minimum quantity value of the order will be reduced to the number of shares remaining. Thus, for example, if a market participant entered a Minimum Quantity Order with a size of 1,000 and a minimum quantity of 500, and the order was marketable against a 600 share order on the book, the remaining 400 shares of the Minimum Quantity Order would post to the book with a minimum quantity restriction of 400 shares.

2. Statutory Basis

BX believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[3] in general, and with Section 6(b)(5) of the Act,[4] in particular, in that the proposal is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest. Specifically, BX believes that the change to the functioning of the Minimum Quantity Order will provide market participants with better control over their trading patterns, thereby providing them with greater potential to improve the quality of their order executions.

B. Self-Regulatory Organization's Statement on Burden on Competition

BX does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended. The changes to the Minimum Quantity Order will enhance the functionality offered by BX to its members, thereby promoting its competitiveness with other exchanges and non-exchange trading venues that already offer similar functionality.

[14] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78f.

[4] 15 U.S.C. 78f(b)(5).

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[5] and Rule 19b–4(f)(6) thereunder.[6]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–BX–2011–069 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BX–2011–069. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet website (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of BX. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BX–2011–069 and should be submitted on or before November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[7]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26854 Filed 10–17–11; 8:45 am]

BILLING CODE 8011–01–P

[5] 15 U.S.C. 78s(b)(3)(A).

[6] 17 CFR 240.19b–4(f)(6).

[7] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65534; File No. SR–ISE–2011–58]

Self-Regulatory Organizations; International Securities Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Competitive Market Maker Trading Rights

October 12, 2011.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on October 3, 2011, the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to refine how it assigns point values to options classes for purposes of Competitive Market Maker trading rights. The text of the proposed rule change is as follows, with deletions marked in [brackets] and additions in italics:

Rule 802. Appointment of Market Makers

(a) No change.

(b) No change.

(c) Appointments to Competitive Market Makers. Competitive market makers may request appointments to options classes traded on the Exchange, subject to the trading licensing requirements of Rule 2013 with respect to index options and Rule 2213 with respect to foreign currency options.

(1) On a quarterly basis, the Exchange shall assign points to each options class equal to its percentage of overall industry volume (not including exclusively traded index options), rounded down to the nearest [tenth] *one hundredth* of a percentage *with a maximum of 15 points.* New listings [with no industry volume in the previous quarter] will be assigned a point value of zero *for the remainder of the quarter in which it was listed.*

(2) No change.

(3) No change.

(d) The Exchange may suspend or terminate any appointment of a market maker under this Rule and may make additional appointments *whenever, in the* Exchange's judgment, the interests of a fair and orderly market are best served by such action. In the case of an Index-Based Product, during the term of that appointment, the Exchange may also base a decision to suspend or terminate a Primary Market Maker's appointment on the failure of the Primary Market Maker to meet the terms of its commitments under paragraph (b)(1) above.

(e) Market Maker Performance. In making appointments to market makers, the Exchange may evaluate the performance of market makers relating to, among other things, quality of markets, competition among market makers, observance of ethical standards, and administrative factors. The Exchange may consider any relevant information, including but not limited to the results of a market maker evaluation questionnaire, trading data, a market maker's regulatory history and such other factors and data as may be pertinent in the circumstances. Moreover, failure by a market maker to meet minimum performance standards may result in, among other things: (1) suspension, termination or restriction of an appointment to one or more of the options classes *appointed to the market maker* [within the market maker's appointed Group]; (2) restriction of appointments to

additional options classes [in the market maker's appointed Group]; or (3) suspension, termination, or restriction of the market makers registration.

Supplementary Material to Rule 802

.01–.02 No change.

* * * * *

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in Sections A, B and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange recently changed the structure of Competitive Market Maker (''CMM'') appointments to give market makers flexibility to choose the options classes to which they are appointed.[3] Under this structure, the Exchange assigns points to each options class equal to its percentage of overall industry volume (not including exclusively-traded index options), rounded down to the nearest tenth of a percentage. A CMM is then permitted to seek appointments to options classes that total twenty points for the first CMM trading right owned or leased by a member, and ten points for each subsequent CMM trading right owned or leased by the same member.[4]

The Exchange proposes to make three refinements to the point values assigned to certain options classes. First, to prevent any one symbol from having a disproportionate weight with respect to CMM trading rights, the Exchange seeks to cap the total number of points an options class is assigned to 15 (equivalent to 15 percent of industry volume). Second, since point values are refreshed on a quarterly basis, we seek to clarify that any new ISE listings during a quarter will have a point value of zero until a point value is determined at the end of the quarter. Finally, when assigning point values, the Exchange proposes to round down to the nearest hundredth of a percentage, rather than a tenth of a percentage, to more precisely reflect an options class' percentage of industry volume.

Finally, the Exchange proposes to make four changes to Rule 802. First, the Exchange proposes to add the words 'whenever, in the' to Rule 802(d). Second, the Exchange proposes to add the words 'appointed to the market maker' to Rule 802(e)(1). Third, the Exchange proposes to delete the words 'within the market maker's appointed Group' from Rule 802(e)(1). Fourth, the Exchange proposes to delete the words 'in the market maker's appointed Group' from Rule 802(e)(2). The Exchange inadvertently failed to make these rule text changes when it recently amended Rule 802.[5]

2. Basis

The basis under the Securities Exchange Act of 1934 (''Exchange Act'') for this proposed rule change is the requirement under Section 6(b)(5) that an exchange have rules that are designed to promote just and equitable principles of trade, and to remove impediments to and perfect the mechanism for a free and open market and a national market system, and in general, to protect investors and the public interest. In particular, the proposal will provide clarity to members regarding how points are assigned to options classes for purposes of CMM trading rights, and assure that the process is administered in an efficient manner.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change: (1) Does not significantly affect the protection of investors or the public interest; (2) does not impose any significant burden on competition; and (3) by its terms does not become operative for 30 days after the date of this filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A)[6] of the Act and Rule 19b–4(f)(6) thereunder.[7]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Exchange Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an E-mail to *rule-comments@sec.gov.* Please include File No. SR–ISE–2011–58 in the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–ISE–2011–58. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your

[3] *See* Securities Exchange Act Release No. 65100 (Aug. 11, 2011), 76 FR 51075 (Aug. 17, 2011) (order approving SR–ISE–2011–33).

[4] CMMs can select the options classes to which they seek appointment, but the Exchange retains the authority to make such appointments and to remove appointments from CMMs based on their performance. *See* ISE Rule 802.

[5] *See supra* note 3.

[6] 15 U.S.C. 78s(b)(3)(A). In addition, Rule 19b–4(f)(6) requires the Exchange to give the Commission written notice of the Exchange's intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[7] 17 CFR 240.19b–4(f)(6).

comments more efficiently, please use only one method. The Commission will post all comments on the Commissions Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of the ISE. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–ISE–2011–58 and should be submitted by November 8, 2011.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[8]

Elizabeth M. Murphy,

Secretary.

[FR Doc. 2011–26853 Filed 10–17–11; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–65358; File No. SR–FINRA–2011–045]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Revise the Series 7 Examination Program

September 20, 2011.

Correction

In notice document 2011–24710 appearing on pages 59751–59754 in the issue of September 27, 2011, make the following correction:

On page 59751, in the third column, the Release No. in the heading is corrected to read as set forth above.

[FR Doc. C1–2011–24710 Filed 10–17–11; 8:45 am]

BILLING CODE 1505–01–D

[8] 17 CFR 200.30–3(a)(12).

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12774 and #12775]

NORTH CAROLINA Disaster Number NC–00036

AGENCY: U.S. Small Business Administration.

ACTION: Amendment 6.

SUMMARY: This is an amendment of the Presidential declaration of a major disaster for the State of NORTH CAROLINA (FEMA–4019–DR), dated 08/31/2011.

Incident: Hurricane Irene.

Incident Period: 08/25/2011 through 09/01/2011.

Effective Date: 10/07/2011.

Physical Loan Application Deadline Date: 10/31/2011.

EIDL Loan Application Deadline Date: 05/31/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: The notice of the Presidential disaster declaration for the State of NORTH CAROLINA, dated 08/31/2011 is hereby amended to include the following areas as adversely affected by the disaster:

Primary Counties (Physical Damage and Economic Injury Loans): Bladen, Columbus, Sampson.

Contiguous Counties (Economic Injury Loans Only):

North Carolina: Cumberland, Robeson.

South Carolina: Dillon.

All other information in the original declaration remains unchanged.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26830 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12879 and #12880]

Pennsylvania Disaster #PA–00045

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a Notice of the Presidential declaration of a major disaster for Public Assistance Only for the Commonwealth of Pennsylvania (FEMA–4030–DR), dated 10/07/2011.

Incident: Tropical Storm Lee.

Incident Period: 09/03/2011 and continuing.

Effective Date: 10/07/2011.

Physical Loan Application Deadline Date: 12/06/2011.

Economic injury (EIDL) Loan Application Deadline Date: 07/09/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing And Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the President's major disaster declaration on 10/07/2011, Private Non-Profit organizations that provide essential services of governmental nature may file disaster loan applications at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Berks, Bradford, Columbia, Dauphin, Juniata, Lancaster, Lebanon, Luzerne, Lycoming, Montour, Schuylkill, Snyder, Sullivan, Susquehanna, Wyoming.

The Interest Rates are:

	Percent
For Physical Damage:	
Non-Profit Organizations With Credit Available Elsewhere ...	3.250
Non-Profit Organizations Without Credit Available Elsewhere	3.000
For Economic Injury:	
Non-Profit Organizations Without Credit Available Elsewhere	3.000

The number assigned to this disaster for physical damage is 128798 and for economic injury is 128808.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26834 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12824 and #12825]

NEW YORK Disaster Number NY–00110

AGENCY: U.S. Small Business Administration.

ACTION: Amendment 5.

SUMMARY: This is an amendment of the Presidential declaration of a major disaster for the State of New York (FEMA–4031–DR), dated 09/13/2011.

Incident: Remnants of Tropical Storm Lee.

Incident Period: 09/07/2011 through 09/11/2011.

Effective Date: 10/07/2011.

Physical Loan Application Deadline Date: 11/14/2011.

EIDL Loan Application Deadline Date: 06/13/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: The notice of the Presidential disaster declaration for the State of NEW YORK, dated 09/13/2011 is hereby amended to include the following areas as adversely affected by the disaster:

Primary Counties: (Physical Damage and Economic Injury Loans) Fulton.

Contiguous Counties: (Economic Injury Loans Only)

New York, Hamilton.

All other information in the original declaration remains unchanged.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26837 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12858 and #12859]

New York Disaster Number NY–00113

AGENCY: U.S. Small Business Administration.

ACTION: Amendment 3.

SUMMARY: This is an amendment of the Presidential declaration of a major disaster for Public Assistance Only for the State of New York (FEMA–4031–DR). dated 09/23/2011.

Incident: Remnants of Tropical Storm Lee.

Incident Period: 09/07/2011 through 09/11/2011.

Effective Date: 10/07/2011.

Physical Loan Application Deadline Date: 11/22/2011.

Economic Injury (EIDL) Loan Application Deadline Date: 06/25/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing And Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: The notice of the President's major disaster declaration for Private Non-Profit organizations in the State of New York, dated 09/23/2011, is hereby amended to include the following areas as adversely affected by the disaster.

Primary Counties: Schoharie.

All other information in the original declaration remains unchanged.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26829 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12815 and #12816]

TEXAS Disaster Number TX–00381

AGENCY: U.S. Small Business Administration.

ACTION: Amendment 6.

SUMMARY: This is an amendment of the Presidential declaration of a major disaster for the State of TEXAS (FEMA–4029–DR), dated 09/09/2011.

Incident: Wildfires.

Incident Period: 08/30/2011 and continuing.

DATES: *Effective Date:* 10/07/2011.

Physical Loan Application Deadline Date: 11/08/2011.

EIDL Loan Application Deadline Date: 06/06/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: The notice of the Presidential disaster declaration for the State of TEXAS, dated 09/09/2011 is hereby amended to include the following areas as adversely affected by the disaster:

Primary Counties: (Physical Damage and Economic Injury Loans) Navarro.

Contiguous Counties: (Economic Injury Loans Only)

All other information in the original declaration remains unchanged.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26839 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12876 and #12877]

New Jersey Disaster #NJ–00022

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Administrative declaration of a disaster for the State of NEW JERSEY dated 10/11/2011.

Incident: Severe Storms and Flooding.

Incident Period: 08/13/2011 through 08/15/2011.

Effective Date: 10/11/2011.

Physical Loan Application Deadline Date: 12/12/2011.

Economic Injury (EIDL) Loan Application Deadline Date: 07/11/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's disaster declaration, applications for disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Gloucester.

Contiguous Counties:
New Jersey: Atlantic, Camden, Cumberland, Salem.
Delaware: New Castle.
Pennsylvania: Delaware, Philadelphia.
The Interest Rates are:

	Percent
For Physical Damage:	
Homeowners With Credit Available Elsewhere	5.000
Homeowners Without Credit Available Elsewhere	2.500
Businesses With Credit Available Elsewhere	6.000
Businesses Without Credit Available Elsewhere	4.000
Non-Profit Organizations With Credit Available Elsewhere	3.250
Non-Profit Organizations Without Credit Available Elsewhere	3.000
For Economic Injury:	
Businesses & Small Agricultural Cooperatives Without Credit Available Elsewhere	4.000
Non-Profit Organizations Without Credit Available Elsewhere	3.000

The number assigned to this disaster for physical damage is 12876 6 and for economic injury is 128770.

The States which received an EIDL Declaration # are New Jersey, Delaware, Pennsylvania.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

Dated: October 11, 2011.

Karen G. Mills,

Administrator.

[FR Doc. 2011–26836 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #12874 and #12875]

Maryland Disaster #MD–00018

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a Notice of the Presidential declaration of a major disaster for Public Assistance Only for the State of Maryland (FEMA–4038–DR), dated 10/05/2011.

Incident: Remnants of Tropical Storm Lee.

Incident Period: 09/06/2011 through 09/09/2011.

Effective Date: 10/05/2011.

Physical Loan Application Deadline Date: 12/05/2011.

Economic Injury (EIDL) Loan Application Deadline Date: 07/05/2012.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street, SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the President's major disaster declaration on 10/05/2011, Private Non-Profit organizations that provide essential services of governmental nature may file disaster loan applications at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Anne Arundel, Cecil, Charles, Prince George's.

The Interest Rates are:

	Percent
For Physical Damage:	
Non-Profit Organizations With Credit Available Elsewhere	3.250
Non-Profit Organizations Without Credit Available Elsewhere	3.000
For Economic Injury:	
Non-Profit Organizations Without Credit Available Elsewhere	3.000

The number assigned to this disaster for physical damage is 128748 and for economic injury is 128758.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

James E. Rivera,

Associate Administrator for Disaster Assistance.

[FR Doc. 2011–26835 Filed 10–17–11; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Senior Executive Service: Performance Review Board Members

AGENCY: U.S. Small Business Administration.

ACTION: Notice of Members for the FY 2011 Performance Review Board.

SUMMARY: Title 5 U.S.C. 4314(c)(4) requires each agency to publish notification of the appointment of individuals who may serve as members of that Agency's Performance Review Board (PRB). The following individuals have been designated to serve on the FY 2011 Performance Review Board for the U.S. Small Business Administration.

1. Delorice Ford, PRB Chairperson, Assistant Administrator Hearings and Appeals
2. Michael Chodos, Associate Administrator for Entrepreneurial Development
3. Nina Levine, Associate General Counsel for Financial Law and Lender Oversight
4. Pravina Raghavan, District Director, New York District Office
5. Tong Qin, Deputy Chief Financial Officer
6. Steven Smits, Associate Administrator for Capital Access
7. Jonathan Swain, Chief of Staff

Karen G. Mills,

Administrator.

[FR Doc. 2011–26833 Filed 10–17–11; 8:45 am]

BILLING CODE P

DEPARTMENT OF STATE

[Public Notice: 7648]

30-Day Notice of Proposed Information Collections: DDTC Information Collections.

ACTION: Notice of request for public comment and submission to OMB of proposed collections of information.

SUMMARY: The Department of State has submitted the following information collection requests to the Office of Management and Budget (OMB) for approval in accordance with the Paperwork Reduction Act of 1995.

- Title of Information Collection: Application/License for Permanent Export of Unclassified Defense Articles and Related Unclassified Technical Data
- OMB Control Number: 1405–0003
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–5
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 2,500
- Estimated Number of Responses: 56,000
- Average Hours per Response: 1 hour
- Total Estimated Burden: 56,000 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Application/License for Temporary Import of Unclassified Defense Articles
- OMB Control Number: 1405–0013

- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–61
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 240
- Estimated Number of Responses: 1,500
- Average Hours per Response: 30 minutes
- Total Estimated Burden: 750 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Application/License for Temporary Export of Unclassified Defense Articles
- OMB Control Number: 1405–0023
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–73
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 510
- Estimated Number of Responses: 5,000
- Average Hours per Response: 1 hour
- Total Estimated Burden: 5,000 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Nontransfer and Use Certificate
- OMB Control Number: 1405–0021
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–83
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 2,600
- Estimated Number of Responses: 9,400
- Average Hours per Response: 1 hour
- Total Estimated Burden: 9,400 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Application/License for Permanent/ Temporary Export or Temporary Import of Classified Defense Articles and Classified Technical Data
- OMB Control Number: 1405–0022
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–85
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 35
- Estimated Number of Responses: 300
- Average Hours per Response: 30 minutes
- Total Estimated Burden: 150 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Authority to Export Defense Articles and Services Sold Under the Foreign Military Sales (FMS) Program
- OMB Control Number: 1405–0051
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: DSP–94
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 250
- Estimated Number of Responses: 2,500
- Average Hours per Response: 30 minutes
- Total Estimated Burden: 1,250 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Application for Amendment to License for Export or Import of Classified or Unclassified Defense Articles and Related Technical Data
- OMB Control Number: 1405–0092
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Numbers: DSP–6, DSP–62, DSP–74, DSP–119
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 700
- Estimated Number of Responses: 7,500
- Average Hours per Response: 30 minutes
- Total Estimated Burden: 3,750 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Request for Approval of Manufacturing License Agreements, Technical Assistance Agreements, and Other Agreements
- OMB Control Number: 1405–0093
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: None
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 650
- Estimated Number of Responses: 8,200
- Average Hours per Response: 2 hours
- Total Estimated Burden: 16,400 hours
- Frequency: On Occasion
- Obligation to Respond: Required to Obtain Benefits
- Title of Information Collection: Statement of Political Contributions, Fees, or Commissions in Connection with the Sale of Defense Articles or Services
- OMB Control Number: 1405–0025
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: None
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 800
- Estimated Number of Responses: 2,000
- Average Hours per Response: 1 hour
- Total Estimated Burden: 2,000 hours
- Frequency: On Occasion
- Obligation to Respond: Mandatory
- Title of Information Collection: Maintenance of Records by Registrants
- OMB Control Number: 1405–0111
- Type of Request: Extension of Currently Approved Collection
- Originating Office: Bureau of Political-Military Affairs, Directorate of Defense Trade Controls, PM/DDTC
- Form Number: None
- Respondents: Business and Nonprofit Organizations
- Estimated Number of Respondents: 9,600
- Estimated Number of Responses: 9,600
- Average Hours per Response: 20 hours
- Total Estimated Burden: 192,000 hours
- Frequency: On Occasion
- Obligation to Respond: Mandatory

DATES: Submit comments to the Office of Management and Budget (OMB) until 30 days from October 18, 2011.

ADDRESSES: Direct comments to the Department of State Desk Officer in the Office of Information and Regulatory Affairs at the Office of Management and

Budget (OMB). You may submit comments by the following methods:

• *E-mail: oira_submission@omb.eop.gov.* You must include the DS form number, information collection title, and OMB control number in the subject line of your message.

• *Fax:* 202–395–5806. Attention: Desk Officer for Department of State.

FOR FURTHER INFORMATION CONTACT: Direct requests for additional information regarding the collections listed in this notice, including requests for copies of the information collection and supporting documents, to Nicholas Memos, PM/DDTC, SA–1, 12th Floor, Directorate of Defense Trade Controls, Bureau of Political-Military Affairs, U.S. Department of State, Washington, DC, 20522–0112, who may be reached via phone at (202) 663–2829, or via e-mail at *memosni@state.gov.*

SUPPLEMENTARY INFORMATION: We are soliciting public comments to permit the Department to:

• Evaluate whether the proposed collection of information is necessary for the proper performance of our functions.

• Evaluate the accuracy of our estimate of the burden of the proposed collection, including the validity of the methodology and assumptions used.

• Enhance the quality, utility, and clarity of the information to be collected.

• Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of technology.

Abstract of proposed collections: The export, temporary import, and temporary export of defense articles, defense services and related technical data are licensed by the Directorate of Defense Trade Controls in accordance with the International Traffic in Arms Regulations (22 CFR parts 120–130) and Section 38 of the Arms Export Control Act. Persons desiring to engage in the export or temporary import of defense articles, defense services, and related technical data must submit an application or written request to conduct the transaction to the Department to obtain a decision whether it is in the interests of U.S. foreign policy and national security to approve the transaction. Additionally, registered manufacturers and exporter must maintain records of defense trade activities for five years.

Methodology: These forms/information collections may be sent to the Directorate of Defense Trade Controls via the following methods: electronically, mail, or personal delivery.

Dated: September 29, 2011.

Robert S. Kovac,

Managing Director of Defense Trade Controls, Bureau of Political-Military Affairs, U.S. Department of State.

[FR Doc. 2011–26943 Filed 10–17–11; 8:45 am]

BILLING CODE 4710–25–P

DEPARTMENT OF STATE

[Public Notice 7649]

Culturally Significant Objects Imported for Exhibition Determinations: ''Projects 96: Haris Epaminonda''

SUMMARY: Notice is hereby given of the following determinations: Pursuant to the authority vested in me by the Act of October 19, 1965 (79 Stat. 985; 22 U.S.C. 2459), Executive Order 12047 of March 27, 1978, the Foreign Affairs Reform and Restructuring Act of 1998 (112 Stat. 2681, *et seq.;* 22 U.S.C. 6501 note, *et seq.*), Delegation of Authority No. 234 of October 1, 1999, Delegation of Authority No. 236–3 of August 28, 2000 (and, as appropriate, Delegation of Authority No. 257 of April 15, 2003), I hereby determine that the objects to be included in the exhibition ''Projects 96: Haris Epaminonda'' imported from abroad for temporary exhibition within the United States, are of cultural significance. The objects are imported pursuant to a loan agreement with the foreign owner or custodian. I also determine that the exhibition or display of the exhibit objects at The Museum of Modern Art, New York, NY, from on or about November 17, 2011, until on or about February 20, 2012, and at possible additional exhibitions or venues yet to be determined, is in the national interest. I have ordered that Public Notice of these Determinations be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: For further information, including a list of the exhibit objects, contact Julie Simpson, Attorney-Adviser, Office of the Legal Adviser, U.S. Department of State (telephone: 202–632–6467). The mailing address is U.S. Department of State, SA–5, L/PD, Fifth Floor (Suite 5H03), Washington, DC 20522–0505.

Dated: October 12, 2011.

J. Adam Ereli,

Principal Deputy Assistant Secretary, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2011–26938 Filed 10–17–11; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2011–0279]

Agency Information Collection Activities; Emergency Approval of a New Information Collection: Motorcoach Passenger and Driver Survey: Motorcoach Safety and Pre-Trip Safety Awareness and Emergency Preparedness Information

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), DOT.

ACTION: Notice and request for information.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, FMCSA announces that the Information Collection Request (ICR) described below will be submitted to the Office of Management and Budget (OMB) for emergency approval. FMCSA requests approval of this ICR by 30 days from the publication of this notice. The purpose of this information collection is to assess the current levels of voluntary compliance by motorcoach operators to provide pre-trip safety awareness and emergency preparedness information to passengers and to obtain passenger opinions of the implementation of the pre-trip program and any recommended improvements. The Department of Transportation (DOT) and FMCSA will use this data to further inform future policy and regulatory decisions, as well as other initiatives to improve motorcoach safety in the United States.

DATES: Please send your comments by November 17, 2011.

ADDRESSES: All comments should reference Federal Docket Management System (FDMS) Docket Number FMCSA–2011–0297. Interested persons are invited to submit written comments on the proposed information collection to the Office of Information and Regulatory Affairs, Office of Management and Budget. Comments should be addressed to the attention of the Desk Officer, Department of Transportation/Federal Motor Carrier Safety Administration, and sent via electronic mail to *http://www.regulations.gov* or faxed to (202) 395–7245, or mailed to the Office of Information and Regulatory Affairs, Office of Management and Budget, Docket Library, Room 10102, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Dee Williams, Office of Policy, Plans, and Regulations, Strategic Planning and Program Evaluation Division Chief, U.S.

Department of Transportation, Federal Motor Carrier Safety Administration, 6th Floor, West Building, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001. *Telephone:* (202) 493–0192; *E-mail Address: dee.williams@dot.gov.* Office hours are from 9 a.m. to 5 p.m., Monday through Friday, except Federal Holidays.

SUPPLEMENTARY INFORMATION:

Title: Motorcoach Passenger and Driver Survey: Motorcoach Safety and Pre-Trip Safety Awareness and Emergency Preparedness Information.

OMB Control Number: 2126–XXXX.

Type of Request: New information collection.

Respondents: Motorcoach passengers and drivers.

Estimated Number of Respondents: 1,050 respondents.

Estimated Time per Response: 10 minutes.

Form Numbers: Form MCSA–5868, Motorcoach Passenger Survey: Pre-Trip Safety Awareness and Emergency Preparedness Information—To collect motorcoach passengers' responses during five one-shot in-person survey events.

Form MCSA–5869, Motorcoach Driver Survey: Pre-Trip Safety Awareness and Emergency Preparedness Information—To collect motorcoach drivers' responses during five one-shot in-person survey events.

Expiration Date: N/A. This is a new information collection.

Frequency of Response: One-time.

Estimated Total Annual Burden: 175 hours [1,050 respondents × 10 minutes/60 minutes = 175 hours].

Background

Due to several recent fatal motorcoach crashes, Congress, DOT, specifically FMCSA, and other Federal oversight agencies, including the National Transportation Safety Board (NTSB), are increasing their scrutiny over the motorcoach industry and the enforcement of and compliance with the Federal Motor Carrier Safety Regulations (FMCSRs). NTSB issued a Safety Recommendation to DOT, H–99–08, requiring motorcoach operators to provide passengers with pre-trip safety awareness information. This recommendation resulted from NTSB's investigation of two motorcoach crashes from the late 1990s which revealed that passengers felt a general sense of panic not knowing what to do on a motorcoach in the case of an emergency. The intent of the recommendation is to empower passengers to take their personal safety into their own hands in the event of an imminent hazard or emergency situation. To address the recommendations issued by NTSB, FMCSA formed a work group that included representatives from the motorcoach industry, motorcoach manufacturers, insurance industry, safety consulting industry, trade associations, State agencies, and other Federal regulatory agencies. The work group decided to address the recommendation by having the motorcoach industry provide pre-trip safety briefings on a voluntary basis.

FMCSA is concerned about the accuracy of self-reported data provided by motorcoach operators and requires third party validation of industry efforts to provide this information to passengers, as well as the effectiveness of the means by which the information is being provided. Currently, compliance is measured during FMCSA's National Passenger Carrier Strike Forces. The data received from these Strike Forces has shown increased adoption levels, however this data is based solely on input from the motorcoach companies and not actual passengers. FMCSA would like to verify that voluntary compliance continues to increase, using different sources, and also collect information on the effectiveness of compliance. FMCSA intends to use this data to address passenger concerns and to provide NTSB and Congress with additional data on voluntary compliance levels.

The goals and objectives of this survey are to assess the current levels of voluntary compliance by motorcoach operators and to obtain passenger opinions of the implementation of the pre-trip safety awareness and emergency preparedness information. This will help eliminate any self-reporting biases by the motorcoach companies; and determine whether the pre-trip safety information is being provided and if it is effective. The Form MCSA–5868 will be used to survey motorcoach passengers and the Form MCSA–5869 will be used to survey motorcoach drivers. The DOT and FMCSA will use this data to further inform future policy and regulatory decisions, as well as other initiatives to improve motorcoach safety in the United States.

Public Comments Invited

The Agency requests emergency processing of this information request. The information collection is essential to FMCSA's safety mission: to reduce crashes, injuries, and fatalities involving large trucks and buses. Expedited review is necessary so FMCSA can use the results to further inform Departmental and Agency efforts currently underway to improve passenger safety. In light of recent fatal crashes, FMCSA believes delay in collection of this information could result in harm to motorcoach passenger safety. You are asked to comment on any aspect of this information collection, including: (1) Whether the proposed collection is necessary for the performance of FMCSA's functions; (2) the accuracy of the estimated burden; (3) ways for FMCSA to enhance the quality, usefulness, and clarity of the collected information; and (4) ways that the burden could be minimized without reducing the quality of the collected information.

Issued on: October 12, 2011.

Kelly Leone,

Associate Administrator for Research and Information Technology.

[FR Doc. 2011–26936 Filed 10–17–11; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Notice To Rescind Notice of Intent To Prepare an Environmental Impact Statement for the Metro Gold Line Foothill Extension, Azusa to Montclair in Los Angeles and San Bernardino Counties, CA

AGENCY: Federal Transit Administration, DOT.

ACTION: Rescind Notice of Intent to Prepare an Environmental Impact Statement.

SUMMARY: The Federal Transit Administration (FTA) and the Metro Gold Line Foothill Extension Construction Authority (the Construction Authority) are issuing this notice to advise the public that the Notice of Intent (NOI) to prepare an Environmental Impact Statement (EIS) for proposed improvements in the Metro Gold Line Foothill Extension Transit Corridor from Azusa to Montclair is being rescinded.

FOR FURTHER INFORMATION CONTACT: Mr. Ray Tellis, Team Leader, Los Angeles Metropolitan Office, Federal Transit Administration, 888 South Figueroa Street, Suite 1850, Los Angeles, CA 90017, phone (213) 202–3950, e-mail *ray.tellis@dot.gov.*

SUPPLEMENTARY INFORMATION: The FTA, in cooperation with the Construction Authority, published a NOI in the **Federal Register** on December 27, 2010 (Volume 75, Number 247) to prepare an EIS for the Metro Gold Line Foothill Extension from Azusa to Montclair Project per 23 U.S.C. 139. The Build Alternative is a Light Rail Transit (LRT) system that would begin at the current

terminus of the Metro Gold Line at the Azusa Citrus Station continuing east to Montclair. Stations plus associated parking and traction power substations were also included in the LRT Alternative. The Construction Authority indicated that in order to preserve project momentum, the Construction Authority has decided not to engage in the environmental process under the National Environmental Policy Act. Therefore, the FTA has determined that there are no Federal actions to be undertaken by the FTA for this project at this time. The NOI will be rescinded accordingly.

Comments and questions concerning the proposed action should be directed to FTA at the address provided above.

Issued on: October 13, 2011.

Leslie T. Rogers,

Regional Administrator, Federal Transit Administration, Region IX.

[FR Doc. 2011–26872 Filed 10–17–11; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. AB 33 (Sub-No. 300X); Docket No. AB–414 (Sub-No. 6X)]

Union Pacific Railroad Company—Abandonment Exemption—in Pottawattamie County, IA; Iowa Interstate Railroad, Ltd.—Discontinuance of Service Exemption—in Pottawattamie County, IA

On October 3, 2011, Union Pacific Railroad Company (UP) and Iowa Interstate Railroad, Ltd. (IAIS) (collectively, petitioners) jointly filed with the Surface Transportation Board a petition under 49 U.S.C. 10502 for exemption from the provisions of 49 U.S.C. 10903 to permit: (1) UP to abandon and IAIS to discontinue service over UP's railroad line known as the Chicago and Great Western Industrial Lead, between milepost 503.6 and milepost 504.05, a distance of approximately 0.45 miles, in Council Bluffs, Pottawattamie County, Iowa (the UP line); (2) UP to abandon and IAIS to discontinue service over UP's connecting track from UP milepost 503.85 on the UP line to the end point at IAIS milepost 486.8, a distance of 400 feet (the UP connecting track); (3) IAIS to discontinue its trackage rights over the UP line and the UP connecting track (the IAIS trackage rights); and (4) UP to discontinue its overhead trackage rights over that portion of IAIS's mainline from IAIS milepost 486.8 to IAIS milepost 488.0, a distance of 1.2 miles (the UP overhead trackage rights). The UP line and UP connecting track traverse United States Postal Service Zip Code 51503 and include no stations; the IAIS line traverses United States Postal Service Zip Codes 51501 and 51503 and also includes no stations.

In addition to an exemption from the prior approval requirements of 49 U.S.C. 10903, petitioners seek an exemption from 49 U.S.C. 10904 (offer of financial assistance procedures) and 10905 (public use provisions). In support, petitioners state that, following abandonment of the UP line and UP connecting track (collectively, the UP lines) and discontinuance of IAIS's trackage rights and UP's overhead trackage rights, UP will sell the UP lines to a shipper, Red Giant Oil Company (Red Giant), subject to a permanent access easement over the UP lines for another shipper, Midwest Walnut Company of Iowa (Midwest Walnut). Red Giant and Midwest Walnut are the only shippers on the UP lines. Petitioners state that, as a consequence of the sale, Red Giant and Midwest Walnut will have permanent, direct access to IAIS, the common carrier railroad that currently serves them; Red Giant and Midwest Walnut will own, control, and use their respective interests in the UP lines as a typical shipper owned industrial lead; and IAIS will serve both Red Giant and Midwest Walnut pursuant to railroad industry track agreements each has entered into with IAIS. These requests will be addressed in the final decision.

Petitioners state that the lines do not contain Federally granted rights-of-way. Any documentation in petitioners' possession will be made available promptly to those requesting it.

The interest of railroad employees will be protected by the conditions set forth in *Oregon Short Line Railroad—Abandonment Portion Goshen Branch Between Firth & Ammon, In Bingham & Bonneville Counties, Idaho,* 360 I.C.C. 91 (1979).

By issuing this notice, the Board is instituting an exemption proceeding pursuant to 49 U.S.C. 10502(b). A final decision will be issued by January 20, 2012.

Any offer of financial assistance (OFA) under 49 CFR 1152.27(b)(2) will be due no later than 10 days after service of a decision granting the petition for exemption. Each OFA must be accompanied by a $1,500 filing fee. *See* 49 CFR 1002.2(f)(25).

All interested persons should be aware that, following abandonment of rail service and salvage of the line, the line may be suitable for other public use, including interim trail use. Any request for a public use condition under 49 CFR 1152.28 or for trail use/rail banking under 49 CFR 1152.29 will be due no later than November 10, 2011. Each trail use request must be accompanied by a $250 filing fee. *See* 49 CFR 1002.2(f)(27).

All filings in response to this notice must refer to Docket Nos. AB 33 (Sub-No. 300X) and AB 414 (Sub-No. 6X), and must be sent to: (1) Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001; (2) for UP—Mack H. Shumate, Jr., Senior General Attorney, 101 N. Wacker Drive, Room 1920, Chicago, IL 60606; and (3) for IAIS—Lanny M. Van Daele, Corporate Counsel, 5900 6th SW., Cedar Rapids, IA 52404. Replies to the joint petition are due on or before November 10, 2011.

Persons seeking further information concerning abandonment procedures may contact the Board's Office of Public Assistance, Governmental Affairs, and Compliance at (202) 245–0238 or refer to the full abandonment or discontinuance regulations at 49 CFR part 1152. Questions concerning environmental issues may be directed to the Board's Office of Environmental Analysis (OEA) at (202) 245–0305. Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.

An environmental assessment (EA) (or environmental impact statement (EIS), if necessary) prepared by OEA will be served upon all parties of record and upon any agencies or other persons who commented during its preparation. Other interested persons may contact OEA to obtain a copy of the EA (or EIS). EAs in these abandonment proceedings normally will be made available within 60 days of the filing of the petition. The deadline for submission of comments on the EA will generally be within 30 days of its service.

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Decided: October 13, 2011.

By the Board, Rachel D. Campbell, Director, Office of Proceedings.

Jeffrey Herzig,

Clearance Clerk.

[FR Doc. 2011–26899 Filed 10–17–11; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. EP 526 (Sub-No. 3)]

Notice of Railroad-Shipper Transportation Advisory Council Vacancy

AGENCY: Surface Transportation Board (Board).

ACTION: Notice of vacancies on the Railroad-Shipper Transportation Advisory Council (RSTAC) and solicitation of nominations.

SUMMARY: The Board hereby gives notice of 7 vacancies on RSTAC for: (1) Representatives of 3 small shippers; (2) representatives of 2 Class I railroads; (3) a representative of a large shipper; and (4) a representative of a Class II or III railroad. The Board is soliciting suggestions for candidates to fill these vacancies.

DATES: Suggestions for candidates for membership on RSTAC are due on December 2, 2011.

ADDRESSES: Suggestions may be submitted either via the Board's e-filing format or in the traditional paper format. Any person using e-filing should attach a document and otherwise comply with the instructions at the E–FILING link on the Board's Web site, at *http://www.stb.dot.gov.* Any person submitting a filing in the traditional paper format should send an original and 10 copies to: Surface Transportation Board, Attn: Docket No. EP 526 (Sub-No. 3), 395 E Street, SW., Washington, DC 20423–0001. Please note that submissions will be available to the public at the Board's offices and posted on the Board's Web site under Docket No. EP 526 (Sub-No. 3).

FOR FURTHER INFORMATION CONTACT: Jamie Rennert at 202–245–0283. Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.

SUPPLEMENTARY INFORMATION: The Board, created by Congress in 1996 to take over many of the functions previously performed by the Interstate Commerce Commission, exercises broad authority over transportation by rail carriers, including regulation of railroad rates and service (49 U.S.C. 10701–10747, 11101–11124), as well as the construction, acquisition, operation, and abandonment of rail lines (49 U.S.C. 10901–10907) and railroad line sales, consolidations, mergers, and common control arrangements (49 U.S.C. 10902, 11323–11327).

RSTAC was established upon the enactment of the ICC Termination Act of 1995 (ICCTA), on December 29, 1995, to advise the Board's Chairman, the Secretary of Transportation, the Committee on Commerce, Science, and Transportation of the Senate, and the Committee on Transportation and Infrastructure of the House of Representatives with respect to rail transportation policy issues that RSTAC considers significant. RSTAC focuses on issues of importance to small shippers and small railroads, including car supply, rates, competition, and procedures for addressing claims. ICCTA directs RSTAC to develop private-sector mechanisms to prevent, or identify and address, obstacles to the most effective and efficient transportation system practicable. The Secretary of Transportation and the members of the Board cooperate with RSTAC in providing research, technical, and other reasonable support. RSTAC also prepares an annual report concerning its activities and recommendations on whatever regulatory or legislative relief it considers appropriate. RSTAC is not subject to the Federal Advisory Committee Act.

RSTAC consists of 19 members. Of this number, 15 members are appointed by the Chairman of the Board, and the remaining 4 members are comprised of the Secretary of Transportation and the Members of the Board, who serve as *ex officio,* nonvoting members. Of the 15 members to be appointed, 9 members are voting members and are appointed from senior executive officers of organizations engaged in the railroad and rail shipping industries. At least 4 of the voting members must be representatives of small shippers as determined by the Chairman, and at least 4 of the voting members must be representatives of Class II or III railroads. The remaining 6 members to be appointed—3 representing Class I railroads and 3 representing large shipper organizations—serve in a nonvoting, advisory capacity, but are entitled to participate in RSTAC deliberations.

RSTAC is required by statute to meet at least semi-annually. In recent years, RSTAC has chosen to meet 4 times a year, with the first meeting each February. Meetings are generally held at the Board's headquarters in Washington, DC, although some may be held in other locations.

The members of RSTAC receive no compensation for their services. RSTAC members are required to provide for the expenses incidental to their service, including travel expenses, as the Board cannot provide for these expenses. The RSTAC Chairman, however, may request funding from the Department of Transportation to cover travel expenses, subject to certain restrictions in ICCTA. RSTAC also may solicit and use private funding for its activities, again subject to certain restrictions in ICCTA. RSTAC members presently have elected to submit annual dues to pay for RSTAC expenses.

RSTAC members must be citizens of the United States and represent as broadly as practicable the various segments of the railroad and rail shipper industries. They may not be full-time employees of the United States. Further, RSTAC members appointed or reappointed after June 18, 2010, are prohibited from serving as federally registered lobbyists during their RSTAC term.

The members of RSTAC are appointed for a term of 3 years. A member may serve after the expiration of his or her term until a successor has taken office. No member will be eligible to serve in excess of 2 consecutive terms.

At the end of this year, 7 vacancies will exist for: representatives of 3 small shippers; Representatives of 2 Class I railroads; a representative of a large shipper; and a representative of a Class II or III railroad, to begin immediately upon their appointment by the Chairman, and to end on December 31, 2014. Suggestions for candidates to fill these vacancies should be submitted in letter form, identifying the name of the candidate, providing a summary of why the candidate is qualified to serve on RSTAC, and containing a representation that the candidate is willing to serve as a member of RSTAC for a 3-year term beginning immediately upon appointment and ending December 31, 2014. Suggestions for a candidate for membership on RSTAC should be filed with the Board by December 2, 2011. Members selected to serve on RSTAC are chosen at the discretion of the Board's Chairman. Please note that submissions will be available to the public at the Board's offices and posted on the Board's Web site under Docket No. EP 526 (Sub-No. 3).

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

Authority: 49 U.S.C. 726.

Decided: October 12, 2011.

By the Board, Rachel D. Campbell, Office of Proceedings.

Jeffrey Herzig,

Clearance Clerk.

[FR Doc. 2011–26880 Filed 10–17–11; 8:45 am]

BILLING CODE 4915–01–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[Docket No. AB 43 (Sub—No. 185X)]

Illinois Central Railroad Company—Discontinuance of Trackage Rights Exemption—in Madison, Yazoo, Holmes, Carroll, Montgomery, Grenada, Yalobusha, Tallahatchie, Panola, Tate, and Desoto Counties, MS

Illinois Central Railroad Company (IC) [1] has filed a verified notice of exemption under 49 CFR pt.1152 subpart F—*Exempt Abandonments and Discontinuances of Service* to discontinue its limited overhead trackage rights over approximately 175.4 miles of rail line known as the Grenada Line, owned by Grenada Railway LLC (GRYR),[2] extending between milepost 403.0 at Southaven and milepost 703.8 near Canton, in Madison, Yazoo, Holmes, Carroll, Montgomery, Grenada, Yalobusha, Tallahatchie, Panola, Tate, and Desoto Counties, Miss.[3] The line traverses United States Postal Service Zip Codes 39046, 39179, 39146, 39079, 39063, 39192, 39176, 38967, 38925, 38926, 38960, 38901, 38953, 38961, 38948, 38927, 38658, 38620, 38606, 38666, 38619, 38668, 38618, 38632, 38651, 38637, and 38671.

IC has certified that: (1) No local traffic has moved via its trackage rights over the line for at least 2 years; (2) any overhead traffic that could be handled via those trackage rights over the line can be rerouted over other lines; (3) no formal complaint filed by a user of IC's trackage rights over the line (or by a state or local government entity acting on behalf of such user) regarding cessation of IC service over the line either is pending with the Surface Transportation Board or with any U.S. District Court or has been decided in favor of complainant within the 2-year period; and (4) the requirements at 49 CFR 1105.12 (newspaper publication), and 49 CFR 1152.50(d)(1) (notice to governmental agencies) have been met.

As a condition to this exemption, any employee adversely affected by the discontinuance of service shall be protected under *Oregon Short Line Railroad—Abandonment Portion Goshen Branch Between Firth & Ammon, in Bingham & Bonneville Counties, Idaho,* 360 I.C.C. 91 (1979). To address whether this condition adequately protects affected employees, a petition for partial revocation under 49 U.S.C. 10502(d) must be filed.

Provided no formal expression of intent to file an offer of financial assistance (OFA) has been received, this exemption will be effective on November 17, 2011, unless stayed pending reconsideration. Petitions to stay that do not involve environmental issues and formal expressions of intent to file an OFA for continued rail service under 49 CFR 1152.27(c)(2) [4] must be filed by October 28, 2011.[5] Petitions to reopen must be filed by November 7, 2011, with the Surface Transportation Board, 395 E Street, SW., Washington, DC 20423–0001.

A copy of any petition filed with the Board should be sent to IC's representative: Jeremy M. Berman, Fletcher & Sippel LLC, 29 North Wacker Drive, Suite 920, Chicago, IL, 60606–2832.

If the verified notice contains false or misleading information, the exemption is void *ab initio.*

Board decisions and notices are available on our Web site at ''*http://WWW.STB.DOT.gov.*''

Decided: October 13, 2011.

By the Board,

Rachel D. Campbell,

Director, Office of Proceedings.

Jeffrey Herzig,

Clearance Clerk.

[FR Doc. 2011–26903 Filed 10–17–11; 8:45 am]

BILLING CODE 4915–01–P

[1] IC is a wholly owned, indirect subsidiary of Canadian National Railway Company and is a Class I rail carrier.

[2] On September 20, 2011, GRYR filed a petition for exemption in Docket No. AB 1087X, *Grenada Railway, LLC—Abandonment Exemption—in Grenada, Montgomery, Carroll, Holmes, Yazoo, & Madison Counties, Miss.,* to abandon an 81.3-mile portion of the Grenada Line from milepost 622.5 near Grenada, Miss., to milepost 703.8 near Canton, Miss. Notice instituting that proceeding was served and published in the *Federal Register* on October 7, 2011 (76 FR 62497–98), and a final decision will be issued by January 6, 2012.

[3] IC notes that it acquired these trackage rights from GRYR by virtue of IC's retention of the trackage rights upon its sale of the Grenada Line to GRYR. *See Gren. Ry.—Acq. & Op. Exemp.—Ill. Cent. R.R. & Waterloo Ry.,* FD 35247 (STB served May 29, 2009).

[4] Each OFA must be accompanied by the filing fee, which currently is set at $1,500. *See* 49 CFR 1002.2(f)(25).

[5] Because this is a discontinuance proceeding and not an abandonment, trail use/rail banking and public use conditions are not appropriate. Likewise, no environmental or historic documentation is required here under 49 CFR 1105.6(c) and 49 CFR 1105.8(b), respectively.

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

Designation of One Entity Pursuant to Executive Order 13224 of September 23, 2001, ''Blocking Property and Prohibiting Transactions With Persons Who Commit, Threaten To Commit, or Support Terrorism''

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Notice.

SUMMARY: The Treasury Department's Office of Foreign Assets Control (''OFAC'') is publishing the name of one entity whose property and interests in property are blocked pursuant to Executive Order 13224 of September 23, 2001, ''Blocking Property and Prohibiting Transactions With Persons Who Commit, Threaten To Commit, or Support Terrorism.''

DATES: The designation by the Director of OFAC of the entity in this notice, pursuant to Executive Order 13224, is effective on October 12, 2011.

FOR FURTHER INFORMATION CONTACT: Assistant Director, Compliance Outreach & Implementation, Office of Foreign Assets Control, Department of the Treasury, Washington, DC 20220, *tel.:* 202/622–2490.

SUPPLEMENTARY INFORMATION:

Electronic and Facsimile Availability

This document and additional information concerning OFAC are available from OFAC's Web site (*http://www.treas.gov/ofac*) or via facsimile through a 24-hour fax-on-demand service, tel.: 202/622–0077.

Background

On September 23, 2001, the President issued Executive Order 13224 (the ''Order'') pursuant to the International Emergency Economic Powers Act, 50 U.S.C. 1701–1706, and the United Nations Participation Act of 1945, 22 U.S.C. 287c. In the Order, the President declared a national emergency to address grave acts of terrorism and threats of terrorism committed by foreign terrorists, including the September 11, 2001 terrorist attacks in New York, Pennsylvania, and at the Pentagon. The Order imposes economic sanctions on persons who have committed, pose a significant risk of committing, or support acts of terrorism. The President identified in the Annex to the Order, as amended by Executive Order 13268 of July 2, 2002, 13 individuals and 16 entities as subject to the economic sanctions. The Order was further amended by Executive Order

13284 of January 23, 2003, to reflect the creation of the Department of Homeland Security.

Section 1 of the Order blocks, with certain exceptions, all property and interests in property that are in or hereafter come within the United States or the possession or control of United States persons, of: (1) Foreign persons listed in the Annex to the Order; (2) foreign persons determined by the Secretary of State, in consultation with the Secretary of the Treasury, the Secretary of the Department of Homeland Security and the Attorney General, to have committed, or to pose a significant risk of committing, acts of terrorism that threaten the security of U.S. nationals or the national security, foreign policy, or economy of the United States; (3) persons determined by the Director of OFAC, in consultation with the Departments of State, Homeland Security and Justice, to be owned or controlled by, or to act for or on behalf of those persons listed in the Annex to the Order or those persons determined to be subject to subsection 1(b), 1(c), or 1(d)(i) of the Order; and (4) except as provided in section 5 of the Order and after such consultation, if any, with foreign authorities as the Secretary of State, in consultation with the Secretary of the Treasury, the Secretary of the Department of Homeland Security and the Attorney General, deems appropriate in the exercise of his discretion, persons determined by the Director of OFAC, in consultation with the Departments of State, Homeland Security and Justice, to assist in, sponsor, or provide financial, material, or technological support for, or financial or other services to or in support of, such acts of terrorism or those persons listed in the Annex to the Order or determined to be subject to the Order or to be otherwise associated with those persons listed in the Annex to the Order or those persons determined to be subject to subsection 1(b), 1(c), or 1(d)(i) of the Order.

On October 12, 2011, the Director of OFAC, in consultation with the Departments of State, Homeland Security, Justice and other relevant agencies, designated, pursuant to one or more of the criteria set forth in subsections 1(b), 1(c) or 1(d) of the Order, one entity whose property and interests in property are blocked pursuant to Executive Order 13224.

The listing for this entity on OFAC's list of Specially Designated Nationals and Blocked Persons appear as follows:

Entities

1. MAHAN AIR (a.k.a. MAHAN AIR CO.), Mahan Air Tower, 21st Floor, Azadeghan Street, Karaj Highway, P.O. Box 14515–411, Tehran, Tehran, Iran; Mahan Air Tower, Azadegan St., Karaj Highway, P.O. Box 411–14515, Tehran, Tehran 1481655761, Iran; No. 21, Mahan Air Tower, Azadegan Street, Jenah Expressway, Beginning of Sheykh Fazlollah Exp. Way, First of Karaj High Way, Tehran, Tehran 1481655761, Iran; [SDGT]

Dated: October 12, 2011.

Adam J. Szubin,

Director, Office of Foreign Assets Control.

[FR Doc. 2011–26882 Filed 10–17–11; 8:45 am]

BILLING CODE 4810–AL–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Open Meeting for the Electronic Tax Administration Advisory Committee (ETAAC)

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of open meeting.

SUMMARY: In 1998 the Internal Revenue Service established the Electronic Tax Administration Advisory Committee (ETAAC).The primary purpose of ETAAC is to provide an organized public forum for discussion of electronic tax administration issues in support of the overriding goal that paperless filing should be the preferred and most convenient method of filing tax and information returns. ETAAC offers constructive observations about current or proposed policies, programs, and procedures, and suggests improvements. Listed is a summary of the agenda along with the planned discussion topics.

Summarized Agenda

8:30 a.m.—Meet and Greet.
9 a.m.—Meeting Opens.
10 a.m.—Meeting Adjourns.
The topic for discussion includes:

IRS Official Response to 2011 ETAAC Recommendations

Note: Last-minute changes to these topics are possible and could prevent advance notice.

DATES: There will be an ETAAC meeting on Wednesday, November 9, 2011. You must register in advance to be put on a guest list to attend the meeting. This meeting will be open to the public, and will be in a room that accommodates approximately 40 people, including members of ETAAC and IRS officials. Seats are available to members of the public on a first-come, first-served basis. Escorts will be provided so attendees are encouraged to arrive at least 30 minutes before the meeting begins. Members of the public may file written statements sharing ideas for electronic tax administration. Send written statements to *etaac@irs.gov.*

ADDRESSES: The meeting will be held at the Internal Revenue Service, 1111 Constitution Avenue, NW., Room 2140, Washington, DC 20024.

FOR FURTHER INFORMATION CONTACT: You must provide your name in advance for the guest list and be able to show your state-issued picture identification on the day of the meeting. Otherwise, you will not be able to attend the meeting as this is a secured building. To receive a copy of the agenda or general information about ETAAC, call Cassandra Daniels on 202–283–2178 or send an e-mail to *etaac@irs.gov* by Friday, November 4, 2011. Notification of intent should include your name, organization and telephone number. Please spell out all names if you leave a voice message.

SUPPLEMENTARY INFORMATION: ETAAC reports to the Director, Return Preparer Office. Increasing participation by external stakeholders in the development and implementation of the strategy for electronic tax administration will help IRS achieve the goal that paperless filing should be the preferred and most convenient method of filing tax and information returns. ETAAC members are not paid for their time or services, but consistent with Federal regulations, they are reimbursed for their travel and lodging expenses to attend the public meetings, working sessions, and an orientation each year.

October 6, 2011.

Diane Fox,

Acting Chief, Relationship Management.

[FR Doc. 2011–26805 Filed 10–17–11; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Senior Executive Service; Combined Performance Review Board (PRB)

AGENCY: Bureau of the Public Debt, Treasury Department.

ACTION: Notice of Members of Combined Performance Review Board (PRB).

SUMMARY: This notice announces the appointment of the members of the Combined Performance Review Board (PRB) for the Bureau of the Public Debt (BPD), the Bureau of Engraving and Printing (BEP), the Financial Management Service (FMS), the United

States Mint, the Alcohol and Tobacco Tax and Trade Bureau (TTB), and the Financial Crimes Enforcement Network (FinCEN). The Combined PRB reviews the performance appraisals of career senior executives who are below the level of bureau head and principal deputy in the bureaus, except for executives below the Assistant Commissioner/Executive Director level in the Bureau of the Public Debt and Financial Management Service. The Combined PRB makes recommendations regarding proposed performance appraisals, ratings, bonuses, pay adjustments, and other appropriate personnel actions.

DATES: The membership of the Combined PRB as described in the Notice is effective on October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Angela Jones, Director, Human Resources Division, Office of Management Services, BPD, (304) 480–8301.

SUPPLEMENTARY INFORMATION: Pursuant to 5 U.S.C. 4314(c)(4), this Notice announces the appointment of the following primary and alternate members to the Combined PRB:

Primary Members

Anita Shandor, Deputy Commissioner, BPD.

Pamela J. Gardiner, Deputy Director, BEP.

Wanda Rogers, Deputy Commissioner, FMS.

Richard Peterson, Deputy Director, United States Mint.

Mary G. Ryan, Deputy Administrator, TTB.

Nicholas V. Colucci, Acting Deputy Director, FinCEN.

Alternate Members

Lori Santamorena, Executive Director, BPD.

Scott Wilson, Associate Director, Management, BEP.

John Kopec, Chief Business Architect/ Assistant Commissioner, FMS.

Marty Greiner, Chief Financial Officer, United States Mint.

John J. Manfreda, Administrator, TTB.

Diane K. Wade, Associate Director, Management, FinCEN.

Van Zeck,

Commissioner.

[FR Doc. 2011–26871 Filed 10–17–11; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF THE TREASURY

Bureau of the Public Debt

Senior Executive Service; Public Debt Performance Review Board (PRB)

AGENCY: Bureau of the Public Debt, Treasury.

ACTION: Notice of Members of Public Debt Performance Review Board.

SUMMARY: This notice announces the appointment of the members of the Public Debt Performance Review Board (PRB) for the Bureau of the Public Debt (BPD). The PRB reviews the performance appraisals of career senior executives who are below the level of Assistant Commissioner/Executive Director and who are not assigned to the Office of the Commissioner in BPD. The PRB makes recommendations regarding proposed performance appraisals, ratings, bonuses, pay adjustments, and other appropriate personnel actions.

DATES: The membership on the Public Debt PRB as described in the Notice is effective on October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Angela Jones, Director, Human Resources Division, Office of Management Services, BPD, (304) 480–8949.

SUPPLEMENTARY INFORMATION: Pursuant to 5 U.S.C. 4314(c)(4), this Notice announces the appointment of the following primary and alternate members to the Public Debt PRB:

Primary Members:

Anita Shandor, Deputy Commissioner, Office of the Commissioner, BPD; Kimberly A. McCoy, Assistant Commissioner, Office of Information Technology, BPD; Cynthia Z. Springer, Assistant Commissioner, Office of Administrative Services, BPD; Paul Crowe, Assistant Commissioner, Office of Retail Securities, BPD.

Alternate Members:

Dara Seaman, Assistant Commissioner, Office of Financing, BPD.

Van Zeck,

Commissioner.

[FR Doc. 2011–26869 Filed 10–17–11; 8:45 am]

BILLING CODE 4810–39–P

DEPARTMENT OF VETERANS AFFAIRS

Advisory Committee on Disability Compensation; Notice of Meeting

The Department of Veterans Affairs (VA) gives notice under Public Law 92–463 (Federal Advisory Committee Act) that the Advisory Committee on Disability Compensation will meet on November 14–15, 2011, at the Saint Regis Hotel, at 923 16th Street, NW., Washington, DC, from 8:30 a.m. to 3 p.m. This meeting is open to the public.

The purpose of the Committee is to advise the Secretary of Veterans Affairs on the maintenance and periodic readjustment of the VA Schedule for Rating Disabilities. The Committee is to assemble and review relevant information relating to the nature and character of disabilities arising from service in the Armed Forces, provide an ongoing assessment of the effectiveness of the rating schedule, and give advice on the most appropriate means of responding to the needs of Veterans relating to disability compensation.

The Committee will receive briefings on issues related to compensation for Veterans with service-connected disabilities and other VA benefits programs. Time will be allocated for receiving public comments in the afternoon. Public comments will be limited to three minutes each. Individuals wishing to make oral statements before the Committee will be accommodated on a first-come, first-served basis. Individuals who speak are invited to submit 1–2 page summaries of their comments at the time of the meeting for inclusion in the official meeting record.

The public may submit written statements for the Committee's review to Corina Negrescu, M.D., M.P.H., Designated Federal Officer, Department of Veterans Affairs, Veterans Benefits Administration, Compensation Service, Regulation Staff (211D), 810 Vermont Avenue, NW., Washington, DC 20420, or e-mail at *Sarah.Wu@va.gov.* Any member of the public wishing to attend the meeting or seeking additional information should contact Ms. Wu at (202) 461–9569.

Dated: October 12, 2011.

By Direction of the Secretary.

Vivian Drake,

Committee Management Officer.

[FR Doc. 2011–26838 Filed 10–17–11; 8:45 am]

BILLING CODE P

DEPARTMENT OF VETERANS AFFAIRS

Advisory Committee on Prosthetics and Special-Disabilities Programs; Notice of Meeting

The Department of Veterans Affairs (VA) gives notice under Public Law 92–463 (Federal Advisory Committee Act)

that a meeting of the Advisory Committee on Prosthetics and Special-Disabilities Programs will be held on November 1–2, 2011, in Room 230, at VA Central Office, 810 Vermont Avenue, NW., Washington, DC. The sessions will convene at 8:30 a.m. on both days, and will adjourn at 4:30 p.m. on November 1 and at 12 noon on November 2. The meeting is open to the public.

The purpose of the Committee is to advise the Secretary of Veterans Affairs on VA's prosthetics programs designed to provide state-of-the art prosthetics and the associated rehabilitation research, development, and evaluation of such technology. The Committee also provides advice to the Secretary on special disabilities programs which are defined as any program administered by the Secretary to serve Veterans with spinal cord injuries, blindness or visual impairments, loss of extremities or loss of function, deafness or hearing impairment, and other serious incapacities in terms of daily life functions.

On November 1, the Committee will be briefed by the Chief Disability and Medical Assessment Officer; Physical Therapy Program Specialist; Executive Director, Federal Recovery Coordination Program; Deputy Director, Recreation Therapy; Director, Amputation System of Care; and Deputy Chief Consultant, Prosthetics and Sensory Aids Service. On November 2, the Committee Chair will provide remarks and the Committee will hear from the VA Librarian on research services available to the Committee. Additionally, the Committee will discuss future agenda topics.

No time will be allocated for receiving oral presentations from the public. However, members of the public may submit written statements for review by the Committee to Mr. Larry N. Long, Designated Federal Officer, Department of Veterans Affairs, Veterans Health Administration, Patient Care Services, Rehabilitation Services (10P4RD), 810 Vermont Avenue, NW., Washington, DC 20420, or by e-mail at *lonlar@va.gov.* Any member of the public wanting additional information or to attend the meeting should contact Mr. Long at (202) 461–7354.

By Direction of the Secretary.

Vivian Drake,

Committee Management Officer.

[FR Doc. 2011–26849 Filed 10–17–11; 8:45 am]

BILLING CODE P

DEPARTMENT OF VETERANS AFFAIRS

Corporate Senior Executive Management Office

Notice of Performance Review Board Members

AGENCY: Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: Under the provisions of 5 U.S.C. 4314(c)(4), agencies are required to publish a notice in the **Federal Register** of the appointment of Performance Review Board (PRB) members. This notice announces the appointment of persons to serve on the Performance Review Board of the Department of Veterans Affairs for fiscal year 2011.

DATES: *Effective Date:* October 18, 2011.

FOR FURTHER INFORMATION CONTACT: Kimberly Litherland, Programs Director, Corporate Senior Executive Management Office, Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420, (202) 461–7887.

SUPPLEMENTARY INFORMATION: The membership of the Department of Veterans Affairs Performance Review Board is as follows:

Jose D. Riojas Assistance Secretary for Operations, Security, and Preparedness (Chair).

Michael Cardarelli, Principal Deputy Under Secretary of Benefits.

Robert Jesse, M.D., PhD, Principal Deputy Under Secretary for Health.

John H. Thompson, Deputy General Counsel.

Georgia Coffey, Deputy Assistance Secretary for Diversity and Inclusion Management (EEO Representative).

Marilee Fitzgerald, Director, Department of Defense Education Activity.

Irene Trowell-Harris, R.N., Ed.D, Director, Center for Women Veterans (Alternate).

Dated: October 5, 2011.

John R. Gingrich,

Chief of Staff, Department of Veterans Affairs.

[FR Doc. 2011–26933 Filed 10–17–11; 8:45 am]

BILLING CODE 8320–01–P

FEDERAL REGISTER

Vol. 76 Tuesday,
No. 201 October 18, 2011

Part II

Department of the Interior

Bureau of Safety and Environmental Enforcement

30 CFR Chapter II

Bureau of Ocean Energy Management

30 CFR Chapter V

Reorganization of Title 30: Bureaus of Safety and Environmental Enforcement and Ocean Energy Management; Final Rule

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Chapter II

Bureau of Ocean Energy Management

30 CFR Chapter V

[Docket ID: BOEM–2011–0070]

RIN 1010–AD79

Reorganization of Title 30: Bureaus of Safety and Environmental Enforcement and Ocean Energy Management

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE); Interior, Bureau of Ocean Energy Management (BOEM); Interior.

ACTION: Direct final rule.

SUMMARY: This rule contains regulations that will be under the authority of two newly formed Bureaus, the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM), both within the Department of the Interior. On May 19, 2010, the Secretary of the Interior announced the separation of the responsibilities performed by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) (formerly the Minerals Management Service) into three new separate organizations: Office of Natural Resources Revenue (ONRR), Bureau of Ocean Energy Management (BOEM), and Bureau of Safety and Environmental Enforcement (BSEE). Those regulations that will apply to the authority of BSEE organization will remain in 30 CFR chapter II, but be retitled ''Bureau of Safety and Environmental Enforcement.'' This rule removes from chapter II those regulations that will apply to the authority of BOEM and recodifies them into a new 30 CFR chapter V entitled ''Bureau of Ocean Energy Management.''

DATES: *Effective Dates:* This rule is effective on October 1, 2011.

FOR FURTHER INFORMATION CONTACT: Kumkum Ray, Regulations and Standards Branch, (703) 787–1604, e-mail address: *kumkum.ray@boemre.gov.*

SUPPLEMENTARY INFORMATION:

Background

Order of Events

On May 19, 2010, the Secretary of the Department of the Interior (Secretary) issued Secretarial Order No. 3299, which announced the restructuring of the former Minerals Management Service (MMS). The restructuring divided the responsibilities of the former MMS into three new bureaus within the Department of the Interior:

(1) Bureau of Ocean Energy Management (BOEM).

(2) Bureau of Safety and Environmental Enforcement (BSEE).

(3) Office of Natural Resources Revenue (ONRR).

On June 18, 2010, the Secretary issued Secretarial Order No. 3302, which announced the name change of the former MMS to Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). This name, BOEMRE, will be in effect until the new organizations are in place October 1, 2011.

On October 1, 2010, the functions of the former Minerals Revenue Management (MRM) officially transferred to ONRR, reporting to the Assistant Secretary for Policy, Management and Budget.

On October 4, 2010, ONRR published a final rule in the **Federal Register** (75 FR 61051), moving the regulations related to its royalty and revenue functions from 30 CFR chapter II to chapter XII.

October 1, 2011 will be the effective date of the separation of the [remaining components of] BOEMRE into BOEM and BSEE.

Responsibilities

Secretarial Order No. 3299 established the responsibilities for BOEM, BSEE, and ONRR as follows:

BOEM will be responsible for conventional (*e.g.,* oil and gas) and renewable energy-related management functions including, but not limited to, activities involving resource evaluation, planning, and leasing, environmental science, and environmental analysis.

BSEE will be responsible for safety and environmental enforcement functions including, but not limited to, the authority to permit activities, inspect, investigate, summon witnesses and produce evidence: levy penalties; cancel or suspend activities; and oversee safety, response and removal preparedness.

ONRR is responsible for royalty and revenue management functions including, but not limited to, royalty and revenue collection, distribution, auditing and compliance, investigation and enforcement, and asset management for both onshore and offshore activities.

Secretarial Order No. 3299 further established that BOEM and BSEE will be under the supervision of the Assistant Secretary for Land and Minerals Management (ASLM) and that ONRR will be under the supervision of the Assistant Secretary for Policy, Management and Budget. This order also directed the ASLM to ''take appropriate steps to ensure that this reorganization will provide that agency decisions are made in compliance with all applicable safety, environmental, and conservation laws and regulations * * *'' The reorganization of these regulations supports this directive.

In a January 19, 2011, statement, the Secretary established the missions and functions of BOEM and BSEE as follows:

- *BOEM Mission:* Responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way.
- *BOEM Functions include:* Leasing, Plan Administration, Environmental Studies, National Environmental Policy Act (NEPA) Analysis, Resource Evaluation, Economic Analysis, and the Renewable Energy Program.
- *BSEE Mission:* Enforce safety and environmental regulations.
- *BSEE Functions include:* All field operations including Permitting and Research, Inspections, Research, Offshore Regulatory Programs, Oil Spill Response, and newly formed Training and Environmental Compliance functions.

Rulemaking Procedure

This rule pertains solely to the organization and codification of existing rules and related technical changes necessitated by a division of one agency into two separate agencies. It makes no changes to the substantive legal rights, obligations, or interests of affected parties. This rule therefore is a ''rule[] of agency organization, procedure or practice'' and is therefore exempt from the notice-and-comment requirements of 5 U.S.C. 553 under 5 U.S.C. 553(b)(A). Additionally, for the same reasons, BOEMRE finds for good cause shown that notice and comment on this rule are unnecessary and contrary to the public interest under 5 U.S.C. 553(b)(B). Because this rule makes no changes to the legal obligations or rights of non-governmental entities, the Department further finds that good cause exists under 5 U.S.C. 553(d)(3) to make this rule effective on October 1, 2011, rather than a full 30 days after publication in the **Federal Register**.

Proposed Rule

BOEM and BSEE will also jointly issue a proposed rule that will address some more substantive changes to the regulations. In part, the proposed rule will address regulatory anomalies created by splitting the functions of one

agency into two bureaus. In certain cases, the split necessitated changing the wording of specific provisions. Rather than changing the wording in this final rule, we have concluded it is more appropriate to do so in a proposed rule. The proposed rule changes will be substantial enough in nature to necessitate public comments and publication of a Notice of Proposed Rulemaking (NPR).

Reorganization of CFR Title 30

Background Information

This final rule assigns the regulations previously codified under Title 30 of the Code of Federal Regulations (30 CFR), chapter II—Minerals Management Service, Department of the Interior, Subchapter A—Minerals Revenue Management, Subchapter B—Offshore, and Subchapter C—Appeals; to BSEE, under chapter II and to BOEM, under chapter V. The assignment of the regulations is based on the responsibilities and authorities established by Secretarial Order No. 3299, separating BSEE and BOEM and the January 19, 2011, statement that further clarified each bureau's mission and functions.

To effectively manage the energy and mineral resources of the Outer Continental Shelf (OCS), the current regulations must be separated based on the responsibilities of the new bureaus. Based on the responsibilities established by Secretarial Order No. 3299, separating BOEMRE into BOEM and BSEE, this direct final rule reorganizes the regulations previously found in 30 CFR chapter II by:

1. Retitling chapter II as ''Bureau of Safety and Environmental Enforcement'';

2. Retaining the regulations that will be under the authority of BSEE in chapter II;

3. Adding a new chapter, ''Chapter V—Bureau of Ocean Energy Management''; and

4. Moving the regulations that will be under the authority of BOEM to 30 CFR chapter V.

In addition to redesignating the regulations to the appropriate bureau, this rule makes minor supporting edits for clarification, consistency, or to reiterate current and longstanding practices. However, the regulatory requirements themselves are not changed. These edits generally fall under one of the following categories:

- Updates to cross-references to reflect the two new sets of rules, such as:
  - Change § 250.101(a) to 550.101(a)),
  - Change § 250.123 to 30 CFR 250.123,
  - Change ''see § 250.111'' to ''see § 250.111 and 30 CFR 550.111'';
- Change references from MMS or BOEMRE to BSEE or BOEM. It should be understood, however, that references to BSEE or BOEM actions before October 1, 2011, refer to the predecessor agency (MMS or BOEMRE) performing the functions specified in the regulations;
- Changes in the text to reference new chapter, section, or title headings;
- Correction of spelling or grammatical errors;
- Changes of physical and Web site addresses;
- Changes of titles, *i.e.,* authorized manager (Regional Director, Regional Supervisor *etc.*), and specifying the appropriate title, based on the bureau (*i.e.,* BSEE Regional Director or BOEM Regional Director); and/or

Cross-References

This direct final rule is not intended to make any substantive changes to the regulations or requirements previously set forth in 30 CFR chapter II. In redesignating the regulations, various provisions of this rule contain cross-references to earlier approvals or other actions taken under redesignated sections. This rule replaces the cross-references to previous sections with cross-references to new sections.

Forms and Information Collection

BOEM and BSEE will rename forms as either BOEM or BSEE forms; MMS will be removed from the form names. Each form will retain its already assigned number, except that all numbers will now be four digits. We will add a zero(s) in front of an existing form number where necessary (*e.g.,* form MMS–123 will now become form BSEE–0123). The forms themselves are not changed by this rule.

There are no Information Collection (IC) burden changes in this rule.

Assignment of Regulations and Explanations

All sections that BSEE retains keep their existing numbers, reflecting their existing location in 30 CFR chapter II. BOEM citations are renumbered using the number ''5'' as the first number for the part, reflecting their new location in 30 CFR chapter V.

The following table (Table A) provides an overview of the assignment of regulations between BOEM and BSEE, by part. Many parts are retained in their entirety by BSEE or moved in their entirety to BOEM. Additional details of how other parts are divided between the two bureaus follow in Tables B through O.

TABLE A—DERIVATION TABLE

Title 30—Mineral Resources

Chapter II—Bureau of Ocean Energy Management, Regulation and Enforcement

Current part	New location	Justification
Subchapter A—Minerals Revenue Management		
Part 203—Relief or Reduction in Royalty Rates.	Retained in its entirety in BSEE, chapter II.	BSEE will oversee the administration of royalty relief awarded after lease issuance as an operational responsibility. However, BOEM will set the terms and conditions of any future leases issued with royalty relief provisions.
Part 219—Distribution and Disbursement of Royalties, Rentals, and Bonuses.	Moved in its entirety to BOEM, chapter V, part 519.	BOEM will perform revenue share calculations for Outer Continental Shelf (OCS) receipts shared under the Gulf of Mexico Energy Security Act (GOMESA). ONRR will continue to distribute the revenue shares to Gulf producing States and Coastal Political Subdivisions.
Subchapter B—Offshore		
Part 250—Oil and Gas and Sulphur Operations in the Outer Continental Shelf.	Responsibilities divided between BOEM and BSEE.	Both bureaus have responsibilities that are related to operations on OCS leases. These responsibilities were divided between the two bureaus as detailed in Table B.

TABLE A—DERIVATION TABLE—Continued

Title 30—Mineral Resources

Chapter II—Bureau of Ocean Energy Management, Regulation and Enforcement

Current part	New location	Justification
Part 251—Geological and Geophysical (G&G) Explorations of the Outer Continental Shelf.	Responsibilities divided between BOEM and BSEE.	BOEM will be responsible for issuing the permits and notices and overseeing the activities under the approved permit, as these are prelease, resource assessment-related activities. BSEE will be responsible for issuing permits for test drilling activities under their responsibilities for operations. Further details are provided in Table C.
Part 252—Outer Continental Shelf (OCS) Oil and Gas Information Program.	Both BOEM and BSEE will have this part in its entirety.	Part 252 regulates how and when the date and information is released by the OCS Oil and Gas Information Program. Since both bureaus will collect, maintain, and use data and information collected under this program, both are responsible for managing the data and determining how and when the data and information are released. Further details are provided in Table D.
Part 253—Oil Spill Financial Responsibility for Offshore Facilities.	Moved to BOEM in its entirety, chapter V, part 553.	BOEM is responsible for all activities related to financial assurance. Oil spill financial responsibility requirements are mandated by the Oil Pollution Act of 1990 (OPA) that applies to oil handling activities at any offshore facility (whether or not involved in oil production) seaward of the coastline. Further details are provided in Table E.
Part 254—Oil-Spill Response Requirements for Facilities Located Seaward of the Coast Line.	Retained in its entirety in BSEE	All oil-spill related activities, except for financial responsibility, will fall under BSEE, under its responsibility for oil-spill response. Further details are provided in Table F.
Part 256—Leasing of Sulphur or Oil and Gas in the Outer Continental Shelf.	Responsibilities divided between BOEM and BSEE.	BOEM has primary responsibility for leasing and leasing-related activities. Some responsibilities related to operations and production will be in both bureaus. Suspension-related requirements will go to BSEE. Further details are provided in Table G.
Part 259—Mineral Leasing: Definitions.	Moved to BOEM in its entirety, chapter V, part 559.	BOEM is responsible for leasing activities. Further details are provided in Table H.
Part 260—Outer Continental Shelf Oil and Gas Leasing.	Moved to BOEM in its entirety, chapter V, part 560.	BOEM is responsible for leasing activities. Further details are provided in Table I.
Part 270—Nondiscrimination in the Outer Continental Shelf.	Both BOEM and BSEE will have this part in its entirety.	Both BOEM and BSEE are responsible for ensuring that lessees and operators comply with 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.'' Further details are provided in Table J.
Part 280—Prospecting for Minerals Other Than Oil, Gas, and Sulphur on the Outer Continental Shelf.	Moved to BOEM in its entirety, chapter V, part 580.	This part regulates 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. These activities fall under BOEM responsibilities for managing the development of offshore resources and activities on unleased land or on lands leased to a third party. Further details are provided in Table K.
Part 281—Leasing of Minerals Other Than Oil, Gas, and Sulphur in the Outer Continental Shelf.	Moved to BOEM in its entirety, chapter V, part 581.	This part regulates leasing for minerals other than oil, gas, and sulphur in the OCS. Leasing activities are a BOEM responsibility. Further details are provided in Table L.
Part 282—Operations in the Outer Continental Shelf for Minerals Other Than Oil, Gas, and Sulphur.	Responsibilities divided between BOEM and BSEE.	Both BOEM and BSEE have responsibilities for operations conducted under a mineral lease for OCS minerals other than oil, gas, or sulphur. These responsibilities were divided between the two bureaus as detailed in Table M.
Part 285—Renewable Energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf.	Moved in its entirety to BOEM, chapter V, part 585.	At this time, the renewable energy program will be managed under BOEM. At a later date, the renewable energy program will be reorganized and a determination will be made regarding what functions will be administered by which agency.
Subchapter C—Appeals		
Part 290—Appeal Procedures	Both BOEM and BSEE will have this part in its entirety.	Appeal procedures apply to decisions and orders issued by both BOEM and BSEE. Further details are provided in Table O.
Part 291—Open and Nondiscriminatory Access to Oil and Gas Pipelines under the Outer Continental Shelf Lands Act.	Retained in its entirety in BSEE	This part deals with access to pipelines. All aspects of pipelines, including operations are under the responsibility of BSEE. Further details are provided in Table P.

The reorganization of the individual parts and subparts is as follows:

Subchapter A—Minerals Revenue Management

Part 203—Relief or Reduction in Royalty Rates—Retained in Its Entirety in BSEE, Chapter II

BSEE is responsible for the regulatory oversight of need-based royalty relief awarded after lease issuance and the tracking of all royalty-free production.

Part 219—Distribution and Disbursement of Royalties, Rentals, and Bonuses—Moved in Its Entirety to BOEM, Chapter V, Part 519

BOEM will perform revenue share calculations for OCS receipts shared under GOMESA.

Subchapter B—Offshore

Part 250—Oil and Gas and Sulphur Operations in the Outer Continental Shelf

Part 250 established the requirements for offshore oil, natural gas, and sulphur operations. These operations include activities after the lease is established. Most of current Part 250 will stay under BSEE, with some sections going to BOEM. The details of this division are as follows.

TABLE B—DETAILED TABLE FOR PART 250

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General		
This subpart establishes the basic regulations for oil, gas, and sulphur exploration, development, and production operations in the OCS. Many of the requirements in this subpart represent joint responsibilities; therefore, they belong in both bureaus. Other requirements are the sole responsibility of one bureau.		
§ 250.101 Authority and applicability.	Both BSEE and BOEM, § 550.101	Establishes authority for the entire part, allowing both bureaus to have some authority for operations in the OCS and both bureaus need to establish their authority. This section also establishes the basic requirements for OCS oil, gas, and sulphur operations.
§ 250.102 What does this part do?	Both BSEE and BOEM, § 550.102	This section describes the purpose of these regulations (parts 250 and 550) and provides a reference table addressing where to find information for conducting OCS operations; it is applicable to the regulations in both bureaus.
§ 250.103 Where can I find more information about the requirements in this part?	Both BSEE and BOEM, § 550.103	This section establishes the authority for the bureaus to issue additional guidance to lessees and operators, in the form of Notices to Lessees and Operators (NTLs), and establishes the expectation of the lessees and operators to respond to that guidance.
§ 250.104 How may I appeal a decision made under MMS regulations?	Both BSEE and BOEM, § 550.104	This section explains how a lessee or operator may appeal a decision made by either BSEE or BOEM, it is informational and important to include in both sets of regulations.
§ 250.105 Definitions	Both BSEE and BOEM, § 550.105	This section contains the definitions used in parts 250 and 550, the same definitions will apply to both sets of regulations.
§ 250.106 What standards will the Director use to regulate lease operations?	Retained by BSEE	This section defines the standards for performance that BSEE will use to regulate lease operations, these operations fall under the authority of BSEE.
§ 250.107 What must I do to protect health, safety, property, and the environment?	Retained by BSEE	This section establishes the expectations for operators to protect health, safety, and the environment, these responsibilities fall under the authority of BSEE.
§ 250.108 What requirements must I follow for cranes and other material-handling equipment?	Retained by BSEE	Addresses cranes and other material-handling equipment, which is related to an offshore operation that is under the authority of BSEE.
§ 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?	Retained by BSEE	These sections address welding requirements, which are related to offshore operations that are under the authority of BSEE.
§ 250.114 How must I install and operate electrical equipment?	Retained by BSEE	Addresses the installation and operation of electrical equipment, which are related to offshore operations that are under the authority of BSEE.
§ 250.115 How do I determine well producibility? § 250.116 How do I determine producibility if my well is in the Gulf of Mexico? § 250.117 How does a determination of well producibility affect royalty status?	Moved to BOEM, §§ 550.115, 550.116, and 550.117.	Addresses well producibility that is under the authority of BOEM.
§ 250.118 Will MMS approve gas injection?	Retained by BSEE	Addresses gas injection operations that are under the authority of BSEE.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.119 Will MMS approve subsurface gas storage?	Moved to BOEM, § 550.119	Addresses subsurface gas storage that is under the authority of BOEM.
§ 250.120 How does injecting, storing, or treating gas affect my royalty payments?	Retained by BSE	These pertain to gas storage operations that are under the authority of BSEE.
§ 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?	Both BSEE and BOEM § 550.122	This section clarifies that an approved storage project has no effect on lease term.
§ 250.123 Will MMS allow gas storage on unleased lands?	Moved to BOEM, § 550.123	This section allows gas storage on unleased lands, through a right-of-use and easement (RUE). RUEs are issued by BOEM, under their responsibility for resource management.
§ 250.124 Will MMS approve gas injection into the cap rock containing a sulphur deposit?	Retained by BSEE	This section addresses gas injection operations. Offshore operations are under the authority of BSEE.
§ 250.125 Service fees	Both BSEE and BOEM, § 550.125	Both BSEE and BOEM will oversee activities that require collection of a service fee.
§ 250.126 Electronic payment instructions.	Both BSEE and BOEM, § 550.126	Provides information on how to pay the fees collected by BSEE and BOEM.
§ 250.130 Why does MMS conduct inspections?	Retained by BSEE	BSEE will be responsible for issuing permits and notices and inspecting the operations under approved leases, plans, and permit.
§ 250.131 Will MMS notify me before conducting an inspection?	Retained by BSEE	BSEE will be responsible for inspecting operations and activities on the OCS.
§ 250.132 What must I do when MMS conducts an inspection?		
§ 250.133 Will MMS reimburse me for my expenses related to inspections?		
§ 250.135 What will MMS do if my operating performance is unacceptable?	Both BSEE and BOEM, §§ 550.135 and 550.136.	BSEE is responsible for finding operator performance unacceptable under the criteria of § 550.136, but the final adjudication is a BOEM action.
§ 250.136 How will MMS determine if my operating performance is unacceptable?		
§ 250.140 When will I receive an oral approval?	Both BSEE and BOEM, § 550.140, except for paragraph (c), which will remain with BSEE only.	Both BSEE and BOEM may grant verbal approvals for activities and operations under their respective authorities. Paragraph (c) addresses oral approvals for gas flaring that will be regulated only by BSEE.
§ 250.141 May I ever use alternate procedures or equipment?	Both BSEE and BOEM, § 550.141	This section explains how a lessee or operator may request to use alternate procedures or equipment that is not addressed in current regulations. It is informational and important to include in both sets of regulations.
§ 250.142 How do I receive approval for departures?	Both BSEE and BOEM, § 550.142	This section provides information on how a lessee or operator can request a departure from the applicable BSEE or BOEM regulations. BSEE and BOEM may grant departures for activities and operations under the respective authorities.
§ 250.143 How do I designate an operator?	Moved to BOEM, § 550.143	This section addresses the designation of an operator that is under the authority of BOEM.
§ 250.144 How do I designate a new operator when a designation of operator terminates?	Moved to BOEM, § 550.144	This section addresses the designation of an operator that is under the authority of BOEM.
§ 250.145 How do I designate an agent or a local agent?	Both BSEE and BOEM, § 550.145	This section addresses the designation of an agent that is under the authority of both BSEE and BOEM.
§ 250.146 Who is responsible for fulfilling leasehold obligations?	Both BSEE and BOEM, § 550.146	This section provides information on who is responsible for fulfilling leasehold obligations. These activities are conducted under the authority of both BSEE and BOEM.
§ 250.150 How do I name facilities and wells in the Gulf of Mexico Region?	Retained by BSEE	This section provides information on naming facilities and wells in the Gulf of Mexico region that is under the authority of BSEE.
§ 250.151 How do I name facilities in the Pacific Region?	Retained by BSEE	This section provides information on naming facilities and wells in the Pacific region that are under the authority of BSEE.
§ 250.152 How do I name facilities in the Alaska Region?	Retained by BSEE	This section provides information on naming facilities and wells in the Alaska region that are under the authority of BSEE.
§ 250.153 Do I have to rename an existing facility or well?	Retained by BSEE	This section provides information on renaming existing facilities and wells that are under the authority of BSEE.
§ 250.154 What identification signs must I display?	Retained by BSEE	This section provides information on the required identification signs that must be displayed that are under the authority of BSEE.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.160 When will MMS grant me a right-of-use and easement, and what requirements must I meet?	Moved to BOEM, § 550.160	This section provides information on the requirements that must be met to obtain a RUE. RUEs are issued by BOEM under their responsibility for resource management.
§ 250.161 What else must I submit with my application?	Moved to BOEM, § 550.161	This section provides information on additional requirements that must be contained in the RUE application. RUEs are issued by BOEM under their responsibility for resource management.
§ 250.162 May I continue my right-of-use and easement after the termination of any lease on which it is situated?	Moved to BOEM, § 550.162	This section provides information on RUEs that are issued by BOEM under their responsibility for resource management.
§ 250.163 If I have a State lease, will MMS grant me a right-of-use and easement?	Moved to BOEM, § 550.163	This section concerns RUEs that are issued by BOEM under their responsibility for resource management.
§ 250.164 If I have a State lease, what conditions apply for a right-of-use and easement?	Moved to BOEM, § 550.164	This section provides information on RUEs that are issued by BOEM under their responsibility for resource management.
§ 250.165 If I have a State lease, what fees do I have to pay for a right-of-use and easement?	Moved to BOEM, § 550.165	This section provides information on RUEs that are issued by BOEM under their responsibility for resource management.
§ 250.166 If I have a State lease, what surety bond must I have for a right-of-use and easement?	Moved to BOEM, § 550.166	This section provides information on RUEs that are issued by BOEM under their responsibility for resource management.
§ 250.168 May operations or production be suspended?	Retained by BSEE	These sections address suspension of operations or production. Offshore operations are under the authority of BSEE.
§ 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?	Retained by BSEE	These sections address suspension of operations or production. Offshore operations are under the authority of BSEE.
§ 250.173 When may the Regional Supervisor direct an SOO or SOP?	Retained by BSEE.	
§ 250.174 When may the Regional Supervisor grant or direct an SOP?	Retained by BSEE.	
§ 250.175 When may the Regional Supervisor grant an SOO?	Retained by BSEE	This section addresses suspension of operations. Offshore operations are under the authority of BSEE.
§ 250.176 Does a suspension affect my royalty payment?	Retained by BSEE	These sections address suspension of operations or production. Offshore operations are under the authority of BSEE.
§ 250.177 What additional requirements may the Regional Supervisor order for a suspension?		
§ 250.180 What am I required to do to keep my lease term in effect?	Retained by BSEE	This section addresses requirements for keeping a lease term in effect. BSEE will determine if a lease meets these requirements.
§ 250.181 When may the Secretary cancel my lease and when am I compensated for cancellation?	Moved to BOEM, § 550.181	This section addresses lease cancellations. Offshore lease administration is under the authority of BOEM. Past the primary lease term, BSEE has greater authority over lease extensions via operations or suspensions; BOEM continues its lease administration function.
§ 250.182 When may the Secretary cancel a lease at the exploration stage?	Moved to BOEM, § 550.182	This section addresses lease cancellations. Offshore lease administration, including lease terms, is under the authority of BOEM. Past the primary lease term, BSEE has greater authority over lease extensions via operations or suspensions; BOEM continues its lease administration function.
§ 250.183 When may MMS or the Secretary extend or cancel a lease at the development and production stage?	Moved to BOEM, § 550.183	This section addresses lease cancellations. Offshore lease administration, is under the authority of BOEM. Past the primary lease term, BSEE has greater authority over lease extensions via operations or suspensions; BOEM continues its lease administration function.
§ 250.184 What is the amount of compensation for lease cancellation?	Moved to BOEM, § 550.184	This section addresses lease cancellations. Offshore lease administration, including lease terms, is under the authority of BOEM.
§ 250.185 When is there no compensation for a lease cancellation?	Moved to BOEM, § 550.185	This section addresses lease cancellations. Offshore lease administration, including lease terms, is under the authority of BOEM.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.186 What reporting information and report forms must I submit?	Both BSEE and BOEM, § 550.186	This section provides information concerning reporting requirements and form submission This information is applicable to both BSEE and BOEM activities.
§ 250.187 What are MMS' incident reporting requirements?	Retained by BSEE	This section addresses incident reporting requirements for offshore operations that are under the authority of BSEE.
§ 250.188 What incidents must I report to MMS and when must I report them?	Retained by BSEE	This section addresses incident reporting requirements for offshore operations that are under the authority of BSEE.
§ 250.189 Reporting requirements for incidents requiring immediate notification.	Retained by BSEE	This section addresses incident reporting requirements for offshore operations that are under the authority of BSEE.
§ 250.190 Reporting requirements for incidents requiring written notification.	Retained by BSEE	This section addresses incident reporting requirements for offshore operations that are under the authority of BSEE.
§ 250.191 How does MMS conduct incident investigations?	Retained by BSEE	This section addresses incident investigations for offshore operations that are under the authority of BSEE.
§ 250.192 What reports and statistics must I submit relating to a hurricane, earthquake, or other natural occurrence?	Retained by BSEE	This section requires operators to submit information relating to the impact of hurricanes on on-going offshore operations, which are under the authority of BSEE.
§ 250.193 Reports and investigations of apparent violations.	Retained by BSEE	This section addresses incident reporting requirements for offshore operations that are under the authority of BSEE.
§ 250.194 How must I protect archaeological resources?	Moved to BOEM, paragraph (c) retained by BSEE and also in BOEM with cross reference.	BOEM is responsible for plans. Paragraph (c) directs operators to report to BSEE any archaeological resource discovered while conducting operations in a lease or right-of-way area.
§ 250.195 What notification does MMS require on the production status of wells?	Retained by BSEE	This section addresses the production status of wells. This information is required to determine when a well begins to actively produce. BSEE will oversee this function under their responsibility for offshore operations.
§ 250.196 Reimbursements for reproduction and processing costs.	Both BSEE and BOEM, § 550.196	Data and information may be requested by either BSEE or BOEM.
§ 250.197 Data and information to be made available to the public or for limited inspection.	BOEM—Introductory paragraph and paragraphs (a)(6), (9), (10), (b), (c)(4), (5), and (6). BSEE—Introductory paragraph and paragraphs (a)(1) through (5), (7), (8), (b), (c)(1) through (5) and (7) retained in BSEE.	Both BSEE and BOEM will collect and be responsible for various types of information. This section describes when the information collected will be made available to the public and what data and information will be made available for limited inspection. The section was divided based on the type of data and information addressed in each paragraph.
§ 250.198 Documents incorporated by reference.	Retained by BSEE	This section addresses documents incorporated by reference and pertains to both BSEE and BOEM activities—*e.g.* Renewable Energy in BOEM.
§ 250.199 Paperwork Reduction Act statements—information collection.	Both BSEE and BOEM, § 550.199	This section addresses the Paperwork Reduction Act that is applicable to both BSEE and BOEM.
Subpart B—Plans and Information		
The plans function, which includes approving Exploration Plans and Development and Production Plans, falls under the jurisdiction of BOEM, under its authority to manage development of the Nation's offshore resources in an environmentally and economically responsible way. Therefore, most of Subpart B is being moved to BOEM. BSEE is responsible for Deepwater Operations Plans (DWOPs).		
§ 250.200 Definitions	Both BSEE and BOEM, § 550.200	Definitions section, the same definitions apply to both bureaus.
§ 250.201 What plans and information must I submit before I conduct any activities on my lease or unit?	Both BSEE and BOEM, § 550.201	This section addresses plans that are the responsibility of BOEM. BSEE is responsible for DWOPs.
§ 250.202 What criteria must the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) meet?	Moved to BOEM, § 550.202	This section addresses plans that are the responsibility of BOEM.
§ 250.203 Where can wells be located under an EP, DPP, or DOCD?	Moved to BOEM, § 550.203	This section addresses plans that are the responsibility of BOEM.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.204 How must I protect the rights of the Federal Government?	Retained by BSEE	This section describes the responsibilities of the operator to protect the rights of the Federal Government while conducting operations on their lease or units. BSEE will be responsible for offshore operations and ensuring operators fulfill these obligations.
§ 250.205 Are there special requirements if my well affects an adjacent property?	Retained by BSEE	This section describes the measures operators must take to protect the rights of adjacent lessees during offshore operations. Offshore operations are under the authority of BSEE.
§ 250.206 How do I submit the EP, DPP, or DOCD?	Moved to BOEM, § 550.206	This section addresses plans that are the responsibility of BOEM.
§ 250.207 What ancillary activities may I conduct?	Moved to BOEM, § 550.207	This section is under the responsibility of BOEM.
§ 250.208 If I conduct ancillary activities, what notices must I provide?	Moved to BOEM, § 550.208	This section is under the responsibility of BOEM.
§ 250.209 What is the MMS review process for the notice?	Moved to BOEM, § 550.209	This section is under the responsibility of BOEM.
§ 250.210 If I conduct ancillary activities, what reporting and data/information retention requirements must I satisfy?	Moved to BOEM, § 550.210	This section is under the responsibility of BOEM.
§ 250.211 What must the EP include?	Moved to BOEM, § 550.211	This section addresses plans that are the responsibility of BOEM.
§ 250.212 What information must accompany the EP?	Moved to BOEM, § 550.212	This section addresses plans that are the responsibility of BOEM.
§ 250.213 What general information must accompany the EP?	Moved to BOEM, § 550.213	This section addresses plans that are the responsibility of BOEM.
§ 250.214 What geological and geophysical (G&G) information must accompany the EP?	Moved to BOEM, § 550.214	This section addresses plans that are the responsibility of BOEM.
§ 250.215 What hydrogen sulfide (H_2S) information must accompany the EP?	Moved to BOEM, § 550.215	This section addresses plans that are the responsibility of BOEM.
§ 250.216 What biological, physical, and socioeconomic information must accompany the EP?	Moved to BOEM, § 550.216	This section addresses plans that are the responsibility of BOEM.
§ 250.217 What solid and liquid wastes and discharges information and cooling water intake information must accompany the EP?	Moved to BOEM, § 550.217	This section addresses plans that are the responsibility of BOEM.
§ 250.218 What air emissions information must accompany the EP?	Moved to BOEM, § 550.218	This section addresses plans that are the responsibility of BOEM.
§ 250.219 What oil and hazardous substance spills information must accompany the EP?	Moved to BOEM, § 550.219	This section addresses plans that are the responsibility of BOEM.
§ 250.220 If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?	Moved to BOEM, § 550.220	This section addresses plans that are the responsibility of BOEM.
§ 250.221 What environmental monitoring information must accompany the EP?	Moved to BOEM, § 550.221	This section addresses plans that are the responsibility of BOEM.
§ 250.222 What lease stipulations information must accompany the EP?	Moved to BOEM, § 550.222	This section addresses plans that are the responsibility of BOEM.
§ 250.223 What mitigation measures information must accompany the EP?	Moved to BOEM, § 550.223	This section addresses plans that are the responsibility of BOEM.
§ 250.224 What information on support vessels, offshore vehicles, and aircraft you will use must accompany the EP?	Moved to BOEM, § 550.224	This section addresses plans that are the responsibility of BOEM.
§ 250.225 What information on the onshore support facilities you will use must accompany the EP?	Moved to BOEM, § 550.225	This section addresses plans that are the responsibility of BOEM.
§ 250.226 What Coastal Zone Management Act (CZMA) information must accompany the EP?	Moved to BOEM, § 550.226	This section addresses plans that are the responsibility of BOEM.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.227 What environmental impact analysis (EIA) information must accompany the EP?	Moved to BOEM, § 550.227	This section addresses plans that are the responsibility of BOEM.
§ 250.228 What administrative information must accompany the EP?	Moved to BOEM, § 550.228	This section addresses plans that are the responsibility of BOEM.
§ 250.231 After receiving the EP, what will MMS do?	Moved to BOEM, § 550.231	This section addresses plans that are the responsibility of BOEM.
§ 250.232 What actions will MMS take after the EP is deemed submitted?	Moved to BOEM, § 550.232	This section addresses plans that are the responsibility of BOEM.
§ 250.233 What decisions will MMS make on the EP and within what timeframe?	Moved to BOEM, § 550.233	This section addresses plans that are the responsibility of BOEM.
§ 250.234 How do I submit a modified EP or resubmit a disapproved EP, and when will MMS make a decision?	Moved to BOEM, § 550.234	This section addresses plans that are the responsibility of BOEM.
§ 250.235 If a State objects to the EP's coastal zone consistency certification, what can I do?	Moved to BOEM, § 550.235	This section addresses plans that are the responsibility of BOEM.
§ 250.241 What must the DPP or DOCD include?	Moved to BOEM, § 550.241	This section addresses plans that are the responsibility of BOEM.
§ 250.242 What information must accompany the DPP or DOCD?	Moved to BOEM, § 550.242	This section addresses plans that are the responsibility of BOEM.
§ 250.243 What general information must accompany the DPP or DOCD?	Moved to BOEM, § 550.243	This section addresses plans that are the responsibility of BOEM.
§ 250.244 What geological and geophysical (G&G) information must accompany the DPP or DOCD?	Moved to BOEM, § 550.244	This section addresses plans that are the responsibility of BOEM.
§ 250.245 What hydrogen sulfide (H_2S) information must accompany the DPP or DOCD?	Moved to BOEM, § 550.245	This section addresses plans that are the responsibility of BOEM.
§ 250.246 What mineral resource conservation information must accompany the DPP or DOCD?	Moved to BOEM, § 550.246	This section addresses plans that are the responsibility of BOEM.
§ 250.247 What biological, physical, and socioeconomic information must accompany the DPP or DOCD?	Moved to BOEM, § 550.247	This section addresses plans that are the responsibility of BOEM.
§ 250.248 What solid and liquid wastes and discharges information and cooling water intake information must accompany the DPP or DOCD?	Moved to BOEM, § 550.248	This section addresses plans that are the responsibility of BOEM.
§ 250.249 What air emissions information must accompany the DPP or DOCD?	Moved to BOEM, § 550.249	This section addresses plans that are the responsibility of BOEM.
§ 250.250 What oil and hazardous substance spills information must accompany the DPP or DOCD?	Moved to BOEM, § 550.250	This section addresses plans that are the responsibility of BOEM.
§ 250.251 If I propose activities in the Alaska OCS Region, what planning information must accompany the DPP?	Moved to BOEM, § 550.251	This section addresses plans that are the responsibility of BOEM.
§ 250.252 What environmental monitoring information must accompany the DPP or DOCD?	Moved to BOEM, § 550.252	This section addresses plans that are the responsibility of BOEM.
§ 250.253 What lease stipulations information must accompany the DPP or DOCD?	Moved to BOEM, § 550.253	This section addresses plans that are the responsibility of BOEM.
§ 250.254 What mitigation measures information must accompany the DPP or DOCD?	Moved to BOEM, § 550.254	This section addresses plans that are the responsibility of BOEM.
§ 250.255 What decommissioning information must accompany the DPP or DOCD?	Moved to BOEM, § 550.255	This section addresses plans that are the responsibility of BOEM.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.256 What related facilities and operations information must accompany the DPP or DOCD?	Moved to BOEM, § 550.256	This section addresses plans that are the responsibility of BOEM.
§ 250.257 What information on the support vessels, offshore vehicles, and aircraft you will use must accompany the DPP or DOCD?	Moved to BOEM, § 550.257	This section addresses plans that are the responsibility of BOEM.
§ 250.258 What information on the onshore support facilities you will use must accompany the DPP or DOCD?	Moved to BOEM, § 550.258	This section addresses plans that are the responsibility of BOEM.
§ 250.259 What sulphur operations information must accompany the DPP or DOCD?	Moved to BOEM, § 550.259	This section addresses plans that are the responsibility of BOEM.
§ 250.260 What Coastal Zone Management Act (CZMA) information must accompany the DPP or DOCD?	Moved to BOEM, § 550.260	This section addresses plans that are the responsibility of BOEM.
§ 250.261 What environmental impact analysis (EIA) information must accompany the DPP or DOCD?	Moved to BOEM, § 550.261	This section addresses plans that are the responsibility of BOEM.
§ 250.262 What administrative information must accompany the DPP or DOCD?	Moved to BOEM, § 550.262	This section addresses plans that are the responsibility of BOEM.
§ 250.266 After receiving the DPP or DOCD, what will MMS do?	Moved to BOEM, § 550.266	This section addresses plans that are the responsibility of BOEM.
§ 250.267 What actions will MMS take after the DPP or DOCD is deemed submitted?	Moved to BOEM, § 550.267	This section addresses plans that are the responsibility of BOEM.
§ 250.268 How does MMS respond to recommendations?	Moved to BOEM, § 550.268	This section addresses plans that are the responsibility of BOEM.
§ 250.269 How will MMS evaluate the environmental impacts of the DPP or DOCD?	Moved to BOEM, § 550.269	This section addresses plans that are the responsibility of BOEM.
§ 250.270 What decisions will MMS make on the DPP or DOCD and within what timeframe?	Moved to BOEM, § 550.270	This section addresses plans that are the responsibility of BOEM.
§ 250.271 For what reasons will MMS disapprove the DPP or DOCD?	Moved to BOEM, § 550.271	This section addresses plans that are the responsibility of BOEM.
§ 250.272 If a State objects to the DPP's or DOCD's coastal zone consistency certification, what can I do?	Moved to BOEM, § 550.272	This section addresses plans that are the responsibility of BOEM.
§ 250.273 How do I submit a modified DPP or DOCD or resubmit a disapproved DPP or DOCD?	Moved to BOEM, § 550.273	This section addresses plans that are the responsibility of BOEM.
§ 250.280 How must I conduct activities under the approved EP, DPP, or DOCD?	Moved to BOEM, § 550.280	This section addresses plans that are the responsibility of BOEM.
§ 250.281 What must I do to conduct activities under the approved EP, DPP, or DOCD?	Moved to BOEM, § 550.281	This section addresses plans that are the responsibility of BOEM.
§ 250.282 Do I have to conduct post-approval monitoring?	Both BSEE and BOEM, § 550.282	Both BOEM and BSEE will have oversight functions for post-approval monitoring.
§ 250.283 When must I revise or supplement the approved EP, DPP, or DOCD?	Moved to BOEM, § 550.283	This section addresses plans that are the responsibility of BOEM.
§ 250.284 How will MMS require revisions to the approved EP, DPP, or DOCD?	Moved to BOEM, § 550.284	This section addresses plans that are the responsibility of BOEM.
§ 250.285 How do I submit revised and supplemental EPs, DPPs, and DOCDs?	Moved to BOEM, § 550.285	This section addresses plans that are the responsibility of BOEM.
§ 250.286 What is a DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.287 For what development projects must I submit a DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.288 When and how must I submit the Conceptual Plan?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.289 What must the Conceptual Plan contain?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.290 What operations require approval of the Conceptual Plan?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.291 When and how must I submit the DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.292 What must the DWOP contain?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.293 What operations require approval of the DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.294 May I combine the Conceptual Plan and the DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.295 When must I revise my DWOP?	Retained by BSEE	This section addresses DWOPs that are part of Field Operations and under the authority of BSEE.
§ 250.296 When and how must I submit a CID or a revision to a CID?	Moved to BOEM, § 550.296	This section addresses Conservation Information Documents (CIDs) that are under the authority of BOEM to manage development of the Nation's offshore resources in an environmentally and economically responsible way.
§ 250.297 What information must a CID contain?	Moved to BOEM, § 550.297	This section addresses CIDs that are under the authority of BOEM to manage development of the Nation's offshore resources in an environmentally and economically responsible way.
§ 250.298 How long will MMS take to evaluate and make a decision on the CID?	Moved to BOEM, § 550.298	This section addresses CIDs that are under the authority of BOEM to manage development of the Nation's offshore resources in an environmentally and economically responsible way.
§ 250.299 What operations require approval of the CID?	Moved to BOEM, § 550.299	This section addresses CIDs that are under the authority of BOEM to manage development of the Nation's offshore resources in an environmentally and economically responsible way.
Subpart C—Pollution Prevention and Control		
§ 250.300 Pollution prevention	Retained by BSEE	This section addresses pollution prevention during offshore operations. Offshore operations are under the authority of BSEE.
§ 250.301 Inspection of facilities	Retained by BSEE	BSEE will be responsible for all inspection activities on the OCS.
§ 250.302 Definitions concerning air quality.	Moved to BOEM, § 550.302	This section pertains to air quality concerns that are under the authority of BOEM.
§ 250.303 Facilities described in a new or revised Exploration Plan or Development and Production Plan.	Moved to BOEM, § 550.303	This section pertains to air quality concerns that are under the authority of BOEM.
§ 250.304 Existing facilities	Moved to BOEM, § 550.304	This section pertains to air quality concerns that are under the authority of BOEM.
Subpart D—Oil and Gas Drilling Operations		
Retained in its entirety by BSEE. This section addresses oil and gas drilling operations on the OCS. Offshore operations are under the authority of BSEE.		
Subpart E—Oil and Gas Well-Completion Operations		
Retained in its entirety by BSEE. BSEE will oversee all well-operations, under Field Operations, under its authority for ensuring safety and environmental compliance on the OCS.		
Subpart F—Oil and Gas Well-Workover Operations		
Retained in its entirety by BSEE. This subpart addresses Oil and Gas Well Workover Operations on the OCS. Offshore operations are the responsibility of BSEE, under its authority for ensuring safety and environmental compliance on the OCS.		
Subpart G—[Reserved]		
Subpart H—Oil and Gas Production Safety Systems		
Retained in its entirety by BSEE. Addresses oil and gas production safety systems used during offshore operations, which are under the authority of BSEE.		
Subpart I—Platforms and Structures		
Retained in its entirety by BSEE. This section addresses platforms and structures on the OCS for offshore operations. Offshore operations are under the authority of BSEE.		

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart J—Pipelines and Pipeline Rights-of-Way		
Mostly retained by BSEE, except for provisions related to bond requirements (§ 250.1011). Bonding for all activities is the responsibility of BOEM, and the bonding section will be moved to § 550.1011. The rest of pipeline operations, including the issuance of pipeline rights-of-way, are under the authority of BSEE.		
§ 250.1000 General requirements.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1001 Definitions	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1002 Design requirements for DOI pipelines.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1003 Installation, testing, and repair requirements for DOI pipelines.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1004 Safety equipment requirements for DOI pipelines.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1005 Inspection requirements for DOI pipelines.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1006 How must I decommission and take out of service a DOI pipeline?	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1007 What to include in applications.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1008 Reports	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. Offshore operations are under the authority of BSEE.
§ 250.1009 Requirements to obtain pipeline right-of-way grants.	Retained by BSEE	This section addresses pipelines and pipeline rights-of-way on the OCS, which are offshore operations. The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1010 General requirements for pipeline right-of-way holders.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1011 Bond requirements for pipeline right-of-way holders.	Moved to BOEM, § 550.1011	All bonding is under the authority of BOEM.
§ 250.1012 Required payments for pipeline right-of-way holders.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1013 Grounds for forfeiture of pipeline right-of-way grants.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1014 When pipeline right-of-way grants expire.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1015 Applications for pipeline right-of-way grants.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1016 Granting pipeline rights-of-way.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1017 Requirements for construction under pipeline right-of-way grants.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1018 Assignment of pipeline right-of-way grants.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
§ 250.1019 Relinquishment of pipeline right-of-way grants.	Retained by BSEE	The pipeline rights-of-way are so closely related to the regulation of pipeline operations that it is most efficient to vest the authority in BSEE.
Subpart K—Oil and Gas Production Requirements		
Mostly retained by BSEE, except for provisions related to static bottomhole pressure surveys and classifying reservoirs; BOEM will oversee these requirements because they are operator reporting requirements that can be separated from BSEE's enforcement responsibilities.		

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 250.1150 What are the general reservoir production requirements?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1151 How often must I conduct well production tests?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1152 How do I conduct well tests?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1153 When must I conduct a static bottomhole pressure survey?	Moved to BOEM, § 550.1153	BOEM will oversee these requirements because they are operator reporting requirements that can be separated from BSEE's enforcement responsibilities.
§ 250.1154 How do I determine if my reservoir is sensitive?	Moved to BOEM, § 550.1154	BOEM will oversee these requirements because they are operator reporting requirements that can be separated from BSEE's enforcement responsibilities.
§ 250.1155 What information must I submit for sensitive reservoirs?	Moved to BOEM, § 550.1155	BOEM will oversee these requirements because they are operator reporting requirements that can be separated from BSEE's enforcement responsibilities.
§ 250.1156 What steps must I take to receive approval to produce within 500 feet of a unit or lease line?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1157 How do I receive approval to produce gas-cap gas from an oil reservoir with an associated gas cap?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1158 How do I receive approval to downhole commingle hydrocarbons?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1159 May the Regional Supervisor limit my well or reservoir production rates?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1160 When may I flare or vent gas?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1161 When may I flare or vent gas for extended periods of time?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1162 When may I burn produced liquid hydrocarbons?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1163 How must I measure gas flaring or venting volumes and liquid hydrocarbon burning volumes, and what records must I maintain?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1164 What are the requirements for flaring or venting gas containing H_2S?	Retained by BSEE	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE.
§ 250.1165 What must I do for enhanced recovery operations?	Responsibilities divided between BSEE and BOEM, § 550.1165(b).	This section addresses oil and gas production requirements that are part of offshore operations and are under the authority of BSEE. Paragraph 550.1165 (b) refers operators to BSEE for approval.
§ 250.1166 What additional reporting is required for developments in the Alaska OCS Region?	Responsibilities divided between BSEE and BOEM, § 550.1166(c).	BSEE will oversee these requirements because they are operator reporting requirements. Paragraph 550.1166(c) requires the lessee/operator to request the Maximum Efficient Rate (MER) when submitting Form BOEM–0127 as required under § 550.1155 for sensitive reservoirs.
§ 250.1167 What information must I submit with forms and for approvals?	Responsibilities divided between BSEE and BOEM.	This section addresses information to be submitted; both BSEE and BOEM functions.
Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security		
Retained in its entirety by BSEE. This subpart addresses production measurement, which is a responsibility of BSEE, under its authority for regulatory enforcement of conservation compliance.		
Subpart M—Unitization		
Retained in its entirety by BSEE. This subpart addresses unitization, which is a responsibility of BSEE, under its authority for regulatory enforcement of conservation compliance.		

TABLE B—DETAILED TABLE FOR PART 250—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart N—Outer Continental Shelf (OCS) Civil Penalties		
Retained in both bureaus in its entirety, with the exception of provisions in current § 250.1460 that are specific to operational violations penalized only by BSEE. BOEM issues civil penalties for violations that occur prior to commencement of lease operations and not involving safety and environmental matters, but arising from the lease management functions and regulations of BOEM. BSEE issues civil penalties for violations that occur after permits are approved; these violations would include violations of lease terms or approved plans that occur during operations.		
Subpart O—Well Control and Production Safety Training		
Retained in its entirety by BSEE. This subpart establishes training requirements for individuals working in the offshore oil and gas industry; which is the responsibility of BSEE, under its authority for regulatory enforcement of safety related to offshore operations.		
Subpart P—Sulphur Operations		
Retained in its entirety by BSEE. Sulphur operations are the responsibility of BSEE, under the authority for regulatory enforcement of safety, environment and conservation compliance of the Nation's offshore resources.		
Subpart Q—Decommissioning Activities		
Retained in its entirety by BSEE. Decommissioning activities are the responsibility of BSEE, under the authority for regulatory enforcement of safety, environment and conservation compliance of the Nation's offshore resources.		
Subpart R—[Reserved]		
Subpart S—Safety and Environmental Management Systems (SEMS)		
Retained in its entirety by BSEE. This subpart addresses operator developed SEMS programs; these programs are the responsibility of BSEE, under the authority for regulatory enforcement of safety, environment and conservation compliance of the Nation's offshore resources.		

Part 251—Geological and Geophysical (G&G) Explorations of the Outer Continental Shelf

This part establishes requirements to conduct G&G activities related to oil, gas, and sulphur on unleased lands, or lands under lease to a third party. Most of this part will be the responsibility of BOEM, under its authority to conduct exploration or scientific research activities. Some sections that address drilling will go to BSEE that address drilling.

TABLE C—DETAILED TABLE FOR PART 251

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
PART 251—GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF		
§ 251.1 Definitions	Both BSEE and BOEM, § 551.1	Definitions section, the same definitions apply to both bureaus.
§ 251.2 Purpose of this part	Moved to BOEM, § 551.2	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.3 Authority and applicability of this part.	Both BSEE and BOEM, § 551.3	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.4 Types of G&G activities that require permits or Notices.	Moved to BOEM, § 551.4	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.5 Applying for permits or filing Notices.	Moved to BOEM, § 551.5	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.6 Obligations and rights under a permit or a Notice.	Moved to BOEM, § 551.6	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.7 Test drilling activities under a permit.	Responsibilities divided between both BSEE and BOEM.	All of paragraph (b) regulates drilling activities, which are operations that require a permit, under the authority of BSEE. All of § 551.7, except (b)(6) and (b)(8), is under BOEM.
§ 251.8 Inspection and reporting requirements for activities under a permit.	Moved to BOEM, § 551.8	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.9 Temporarily stopping, canceling, or relinquishing activities approved under a permit.	Moved to BOEM, § 551.9	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.10 Penalties and appeals	Moved to BOEM, § 551.10	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.11 Submission, inspection, and selection of geological data and information collected under a permit and processed by permittees or third parties.	Moved to BOEM, § 551.11	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.

TABLE C—DETAILED TABLE FOR PART 251—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 251.12 Submission, inspection, and selection of geophysical data and information collected under a permit and processed by permittees or third parties.	Moved to BOEM, § 551.12	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.13 Reimbursement for the costs of reproducing data and information and certain processing costs.	Moved to BOEM, § 551.13	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.14 Protecting and disclosing data and information submitted to MMS under a permit.	Moved to BOEM, § 551.14	This section addresses prelease G&G activities. Prelease activities are under the authority of BOEM.
§ 251.15 Authority for information collection.	In both BSEE and BOEM § 551.15	This section establishes the authority for the bureaus to collect the required information from lessees and operators who conduct business on the OCS. Information collection is required in this part for aspects regulated by both BSEE and BOEM.

Part 252—Outer Continental Shelf (OCS) Oil and Gas Information Program

Both BOEM and BSEE will have this part in its entirety. Both bureaus will be responsible for collecting and maintaining certain data and information. This subpart establishes the responsibilities of the bureau for protecting and releasing this data.

TABLE D—DETAILED TABLE FOR PART 252

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
PART 252—OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM		
§ 252.1 Purpose	In both BSEE and BOEM § 552.1	Both BSEE and BOEM will collect, maintain, and use data collected under this program. Both bureaus are responsible for managing the data and determining how and when the data is released.
§ 252.2 Definitions	In both BSEE and BOEM § 552.2	Definitions section. The same definitions apply to both sets of regulations.
§ 252.3 Oil and gas data and information to be provided for use in the OCS Oil and Gas Information Program.	In both BSEE and BOEM § 552.3	Both BSEE and BOEM will collect.
§ 252.4 Summary Report to affected States.	In both BSEE and BOEM § 552.4	Both BSEE and BOEM will collect.
§ 252.5 Information to be made available to affected States.	In both BSEE and BOEM § 552.5	Both BSEE and BOEM will collect.
§ 252.6 Freedom of Information Act requirements.	In both BSEE and BOEM § 552.6	Both BSEE and BOEM will collect.
§ 252.7 Privileged and proprietary data and information to be made available to affected States.	In both BSEE and BOEM § 552.7	Both BSEE and BOEM will collect.

Part 253—Oil Spill Financial Responsibility for Offshore Facilities—Moved to BOEM in Its Entirety, Chapter V Part 523

All financial responsibility functions will be under the authority of BOEM, under its mission to manage the development of offshore resources in an economically responsible way.

TABLE E—DETAILED TABLE FOR PART 253

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General		
§ 253.1 What is the purpose of this part?	Moved to BOEM, § 553.1	BOEM is responsible for all activities related to financial assurance. OPA financial responsibility is required of all oil handling facilities seaward of the coastline, whether production facilities or not and whether Federal or not.
§ 253.3 How are the terms used in this regulation defined?	Moved to BOEM, § 553.3	BOEM is responsible for all activities related to financial assurance.
§ 253.5 What is the authority for collecting Oil Spill Financial Responsibility (OSFR) information?	Moved to BOEM, § 553.5	BOEM is responsible for all activities related to financial assurance.
Subpart B—Applicability and Amount of OSFR		
§ 253.10 What facilities does this part cover?	Moved to BOEM, § 553.10	BOEM is responsible for all activities related to financial assurance.
§ 253.11 Who must demonstrate OSFR?	Moved to BOEM, § 553.11	BOEM is responsible for all activities related to financial assurance.
§ 253.12 May I ask MMS for a determination of whether I must demonstrate OSFR?	Moved to BOEM, § 553.12	BOEM is responsible for all activities related to financial assurance.
§ 253.13 How much OSFR must I demonstrate?	Moved to BOEM, § 553.13	BOEM is responsible for all activities related to financial assurance.
§ 253.14 How do I determine the worst case oil-spill discharge volume?	Moved to BOEM, § 553.14	BOEM is responsible for all activities related to financial assurance.
§ 253.15 What are my general OSFR compliance responsibilities?	Moved to BOEM, § 553.15	BOEM is responsible for all activities related to financial assurance.
Subpart C—Methods for Demonstrating OSFR		
§ 253.20 What methods may I use to demonstrate OSFR?	Moved to BOEM, § 553.20	BOEM is responsible for all activities related to financial assurance.
§ 253.21 How can I use self-insurance as OSFR evidence?	Moved to BOEM, § 553.21	BOEM is responsible for all activities related to financial assurance.
§ 253.22 How do I apply to use self-insurance as OSFR evidence?	Moved to BOEM, § 553.22	BOEM is responsible for all activities related to financial assurance.
§ 253.23 What information must I submit to support my net worth demonstration?	Moved to BOEM, § 553.23	BOEM is responsible for all activities related to financial assurance.
§ 253.24 When I submit audited annual financial statements to verify my net worth, what standards must they meet?	Moved to BOEM, § 553.24	BOEM is responsible for all activities related to financial assurance.
§ 253.25 What financial test procedures must I use to determine the amount of self-insurance allowed as OSFR evidence based on net worth?	Moved to BOEM, § 553.25	BOEM is responsible for all activities related to financial assurance.
§ 253.26 What information must I submit to support my unencumbered assets demonstration?	Moved to BOEM, § 553.26	BOEM is responsible for all activities related to financial assurance.
§ 253.27 When I submit audited annual financial statements to verify my unencumbered assets, what standards must they meet?	Moved to BOEM, § 553.27	BOEM is responsible for all activities related to financial assurance.
§ 253.28 What financial test procedures must I use to evaluate the amount of self-insurance allowed as OSFR evidence based on unencumbered assets?	Moved to BOEM, § 553.28	BOEM is responsible for all activities related to financial assurance.
§ 253.29 How can I use insurance as OSFR evidence?	Moved to BOEM, § 553.29	BOEM is responsible for all activities related to financial assurance.
§ 253.30 How can I use an indemnity as OSFR evidence?	Moved to BOEM, § 553.30	BOEM is responsible for all activities related to financial assurance.
§ 253.31 How can I use a surety bond as OSFR evidence?	Moved to BOEM, § 553.31	BOEM is responsible for all activities related to financial assurance.

TABLE E—DETAILED TABLE FOR PART 253—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 253.32 Are there alternative methods to demonstrate OSFR?	Moved to BOEM, § 553.32	BOEM is responsible for all activities related to financial assurance.
Subpart D—Requirements for Submitting OSFR Information		
§ 253.40 What OSFR evidence must I submit to MMS?	Moved to BOEM, § 553.40	BOEM is responsible for all activities related to financial assurance.
§ 253.41 What terms must I include in my OSFR evidence?	Moved to BOEM, § 553.41	BOEM is responsible for all activities related to financial assurance.
§ 253.42 How can I amend my list of COFs?	Moved to BOEM, § 553.42	BOEM is responsible for all activities related to financial assurance.
§ 253.43 When is my OSFR demonstration or the amendment to my OSFR demonstration effective?	Moved to BOEM, § 553.43	BOEM is responsible for all activities related to financial assurance.
§ 253.44 [Reserved]	§ 553.44 [Reserved]	BOEM is responsible for all activities related to financial assurance.
§ 253.45 Where do I send my OSFR evidence?	Moved to BOEM, § 553.45	BOEM is responsible for all activities related to financial assurance.
Subpart E—Revocation and Penalties		
§ 253.50 How can MMS refuse or invalidate my OSFR evidence?	Moved to BOEM, § 553.50	BOEM is responsible for all activities related to financial assurance.
§ 253.51 What are the penalties for not complying with this part?	Moved to BOEM, § 553.51	BOEM is responsible for all activities related to financial assurance.
Subpart F—Claims for Oil-Spill Removal Costs and Damages		
§ 253.60 To whom may I present a claim?	Moved to BOEM, § 553.60	BOEM is responsible for all activities related to financial assurance.
§ 253.61 When is a guarantor subject to direct action for claims?	Moved to BOEM, § 553.61	BOEM is responsible for all activities related to financial assurance.
§ 253.62 What are the designated applicant's notification obligations regarding a claim?	Moved to BOEM, § 553.62	BOEM is responsible for all activities related to financial assurance.
Appendix—Appendix to Part 253—List of U.S. Geological Survey Topographic Maps.	Moved to BOEM, Appendix to part 553.	BOEM is responsible for all activities related to financial assurance.

Part 254—Oil-Spill Response Requirements for Facilities Located Seaward of the Coast Line—Retained in Its Entirety in BSEE

All oil-spill response functions will be managed by BSEE under its responsibility for enforcement of environmental compliance requirements.

TABLE F—DETAILED TABLE FOR PART 254

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General		
§ 254.1 Who must submit a spill-response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.2 When must I submit a response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.3 May I cover more than one facility in my response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.4 May I reference other documents in my response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.5 General response plan requirements.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.6 Definitions	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.7 How do I submit my response plan to the MMS?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.

TABLE F—DETAILED TABLE FOR PART 254—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 254.8 May I appeal decisions under this part?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.9 Authority for information collection.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
Subpart B—Oil-Spill Response Plans for Outer Continental Shelf Facilities		
§ 254.20 Purpose	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.21 How must I format my response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.22 What information must I include in the ''Introduction and plan contents'' section?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.23 What information must I include in the ''Emergency response action plan'' section?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.24 What information must I include in the ''Equipment inventory'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.25 What information must I include in the ''Contractual agreements'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.26 What information must I include in the ''Worst case discharge scenario'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.27 What information must I include in the ''Dispersant use plan'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.28 What information must I include in the ''In situ burning plan'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.29 What information must I include in the ''Training and drills'' appendix?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.30 When must I revise my response plan?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
Subpart C—Related Requirements for Outer Continental Shelf Facilities		
§ 254.40 Records	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.41 Training your response personnel.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.42 Exercises for your response personnel and equipment.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.43 Maintenance and periodic inspection of response equipment.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.44 Calculating response equipment effective daily recovery capacities.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.45 Verifying the capabilities of your response equipment.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.46 Whom do I notify if an oil spill occurs?	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.47 Determining the volume of oil of your worst case discharge scenario.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
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.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.51 Modifying an existing OCS response plan.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.52 Following the format for an OCS response plan.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.

TABLE F—DETAILED TABLE FOR PART 254—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 254.53 Submitting a response plan developed under State requirements.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.
§ 254.54 Spill prevention for facilities located in State waters seaward of the coast line.	Retained in its entirety in BSEE, chapter II.	All oil spill related regulations, except for financial responsibility, are under BSEE, under its responsibility for oil spill response.

Part 256—Leasing of Sulphur or Oil and Gas in the Outer Continental Shelf

This part establishes leasing requirements for sulphur, oil, and natural gas. Most of this part will be under the responsibility of BOEM under its authority to manage the development of the Nation's offshore resources in an environmentally and economically responsible way. Some sections will go to BSEE that address lease extensions by drilling and suspensions of operations or production.

TABLE G—DETAILED TABLE FOR PART 256

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General		
§ 256.0 Authority for information collection.	Moved to BOEM, § 556.0	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.1 Purpose	Moved to BOEM, § 556.1, retained purpose except for right-of-way grant clause; under BSEE retained right-of-way grant clause.	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.2 Policy	Moved to BOEM, § 556.2	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.4 Authority	Moved to BOEM, § 556.4	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.5 Definitions	Moved to BOEM, § 556.5	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.7 Cross references	Both BSEE and BOEM § 556.7	This section contains cross references that are pertinent to both BSEE and BOEM activities.
§ 256.8 Leasing maps and diagrams.	Moved to BOEM, § 556.8	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.10 Information to States	Moved to BOEM, § 556.10	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.11 Helium	Moved to BOEM, § 556.11	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.12 Supplemental sales	Moved to BOEM, § 556.12	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart B—Oil and Gas Leasing Program		
§ 256.16 Receipt and consideration of nominations; public notice and participation.	Moved to BOEM, § 556.16	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.17 Review by State and local governments and other persons.	Moved to BOEM, § 556.17	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.19 Periodic consultation with interested parties.	Moved to BOEM, § 556.19	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.20 Consideration of coastal zone management program.	Moved to BOEM, § 556.20	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart C—Reports From Federal Agencies		
§ 256.22 General	Moved to BOEM, § 556.22	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart D—Call for Information and Nominations		
§ 256.23 Information on areas	Moved to BOEM, § 556.23	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.25 Areas near coastal states.	Moved to BOEM, § 556.25	This section addresses leasing activities on the OCS that are under the authority of BOEM.

TABLE G—DETAILED TABLE FOR PART 256—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart E—Area Identification and Tract Size		
§ 256.26 General	Moved to BOEM, § 556.26	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.28 Tract size	Moved to BOEM, § 556.28	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart F—Lease Sales		
§ 256.29 Proposed notice of sale	Moved to BOEM, § 556.29	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.31 State comments	Moved to BOEM, § 556.31	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.32 Notice of sale	Moved to BOEM, § 556.32	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart G—Issuance of Leases		
§ 256.35 Qualifications of lessees	Moved to BOEM, § 556.35	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.37 Lease term	Moved to BOEM, § 556.37	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.38 Joint bidding provisions	Moved to BOEM, § 556.38	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.40 Definitions	Moved to BOEM, § 556.40	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.41 Joint bidding requirements.	Moved to BOEM, § 556.41	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.43 Chargeability for production.	Moved to BOEM, § 556.43	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.44 Bids disqualified	Moved to BOEM, § 556.44	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.46 Submission of bids	Moved to BOEM, § 556.46	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.47 Award of leases	Moved to BOEM, § 556.47	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.49 Lease form	Moved to BOEM, § 556.49	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.50 Dating of leases	Moved to BOEM, § 556.50	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart H—Rentals and Royalties [Reserved]		
Subpart I—Bonding		
§ 256.52 Bond requirements for an oil and gas or sulphur lease.	Moved to BOEM, § 556.52	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.53 Additional bonds	Moved to BOEM, § 556.53	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.54 General requirements for bonds.	Moved to BOEM, § 556.54	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.55 Lapse of bond	Moved to BOEM, § 556.55	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.56 Lease-specific abandonment accounts.	Moved to BOEM, § 556.56	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.57 Using a third-party guarantee instead of a bond.	Moved to BOEM, § 556.57	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.58 Termination of the period of liability and cancellation of a bond.	Moved to BOEM, § 556.58	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.59 Forfeiture of bonds and/or other securities.	Moved to BOEM, § 556.59	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart J—Assignments, Transfers, and Extensions		
§ 256.62 Assignment of lease or interest in lease.	Moved to BOEM, § 556.62	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.63 Service fees	Moved to BOEM, § 556.63	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.64 How to file transfers	Moved to BOEM, § 556.64	This section addresses leasing activities on the OCS that are under the authority of BOEM.

TABLE G—DETAILED TABLE FOR PART 256—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 256.65 Attorney General review	Moved to BOEM, § 556.65	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.67 Separate filings for assignments.	Moved to BOEM, § 556.67	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.68 Effect of assignment of a particular tract.	Moved to BOEM, § 556.68	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.70 Extension of lease by drilling or well reworking operations.	Both BSEE and BOEM § 556.70 ...	Needed by both agencies.
§ 256.71 Directional drilling	Both BSEE and BOEM § 556.71 ...	Needed by both agencies.
§ 256.72 Compensatory payments as production.	Both BSEE and BOEM § 556.72 ...	Needed by both agencies.
§ 256.73 Effect of suspensions on lease term.	Retained by BSEE	This section addresses enforcement of suspension activities on the OCS that is under the authority of BSEE. Beyond the primary lease term, BSEE's oversight over operations and production and suspensions thereof determine the lease term.
Subpart K—Termination of Leases		
§ 256.76 Relinquishment of leases or parts of leases.	Moved to BOEM, § 556.76	This section addresses leasing administration on the OCS that are under the authority of BOEM.
§ 256.77 Cancellation of leases	Both BSEE and BOEM, § 556.77 ..	BOEM is authorized to cancel leases. BSEE has the authority to initiate lease cancellation.
Subpart L—Section 6 Leases		
§ 256.79 Effect of regulations on lease.	Both BSEE and BOEM § 556.79 ...	Needed by both agencies.
§ 256.80 Leases of other minerals	Moved to BOEM, § 556.80	This section addresses leasing administration on the OCS that are under the authority of BOEM.
Subpart M—Studies		
§ 256.82 Environmental studies	Moved to BOEM, § 556.82	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart N—Bonus or Royalty Credits for Exchange of Certain Leases		
Offshore Florida		
§ 256.90 Which leases may I exchange for a bonus or royalty credit?	Moved to BOEM, § 556.90	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.91 How much bonus or royalty credit will MMS grant in exchange for a lease?	Moved to BOEM, § 556.91	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.92 What must I do to obtain a bonus or royalty credit?	Moved to BOEM, § 556.92	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.93 How is the bonus or royalty credit allocated among multiple lease owners?	Moved to BOEM, § 556.93	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.94 How may I use the bonus or royalty credit?	Moved to BOEM, § 556.94	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 256.95 How do I transfer a bonus or royalty credit to another person?	Moved to BOEM, § 556.95	This section addresses leasing activities on the OCS that are under the authority of BOEM.
APPENDIX A PART 256—Appendix A to Part 256—Oil and Gas Cash Bonus Bid.	Moved to BOEM, APPENDIX A PART 556.	This section addresses leasing activities on the OCS that are under the authority of BOEM.

Part 259—Mineral Leasing: Definitions—Moved to BOEM in Its Entirety, Chapter V Part 559

TABLE H—DETAILED TABLE FOR PART 259

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 259.001 Purpose and scope	Moved to BOEM, § 559.001	This section addresses definitions used in lease administration under the authority of BOEM.
§ 259.002 Definitions	Moved to BOEM, § 559.002	This section used in lease administration under the authority of BOEM.

Part 260—Outer Continental Shelf Oil and Gas Leasing—Moved to BOEM in Its Entirety, Chapter V, Part 560

BOEM is responsible for lease sales, bidding systems, the regulatory oversight of incentive-based royalty relief and establishing royalty relief thresholds.

TABLE I—DETAILED TABLE FOR PART 260

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General Provisions		
§ 260.1 What is the purpose of this part?	Moved to BOEM, § 560.1	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.2 What definitions apply to this part?	Moved to BOEM, § 560.2	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.3 What is MMS's authority to collect information?	Moved to BOEM, § 560.3	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart B—Bidding Systems		
§ 260.101 What is the purpose of this subpart?	Moved to BOEM, § 560.101	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.102 What definitions apply to this subpart?	Moved to BOEM, § 560.102	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.110 What bidding systems may MMS use?	Moved to BOEM, § 560.110	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.111 What conditions apply to the bidding systems that MMS uses?	Moved to BOEM, § 560.111	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.112 How do royalty suspension volumes apply to eligible leases?	Moved to BOEM, § 560.112	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.113 When does an eligible lease qualify for a royalty suspension volume?	Moved to BOEM, § 560.113	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.114 How does MMS assign and monitor royalty suspension volumes for eligible leases?	Moved to BOEM, § 560.114	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.115 How long will a royalty suspension volume for an eligible lease be effective?	Moved to BOEM, § 560.115	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.116 How do I measure natural gas production on my eligible lease?	Moved to BOEM, § 560.116	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.120 How does royalty suspension apply to leases issued in a sale held after November 2000?	Moved to BOEM, § 560.120	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.121 When does a lease issued in a sale held after November 2000 get a royalty suspension?	Moved to BOEM, § 560.121	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.122 How long will a royalty suspension volume be effective for a lease issued in a sale held after November 2000?	Moved to BOEM, § 560.122	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.123 How do I measure natural gas production for a lease issued in a sale held after November 2000?	Moved to BOEM, § 560.123	This section addresses leasing activities on the OCS that are under the authority of BOEM.

TABLE I—DETAILED TABLE FOR PART 260—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 260.124 How will royalty suspension apply if MMS assigns a lease issued in a sale held after November 2000 to a field that has a pre-Act lease?	Moved to BOEM, § 560.124	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.130 What criteria does MMS use for selecting bidding systems and bidding system components?	Moved to BOEM, § 560.130	This section addresses leasing activities on the OCS that are under the authority of BOEM.
Subpart C—[Reserved]		
Subpart D—Joint Bidding		
§ 260.301 What is the purpose of this subpart?	Moved to BOEM, § 560.301	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.302 What definitions apply to this subpart?	Moved to BOEM, § 560.302	This section addresses leasing activities on the OCS that are under the authority of BOEM.
§ 260.303 What are the joint bidding requirements?	Moved to BOEM, § 560.303	This section addresses leasing activities on the OCS that are under the authority of BOEM.

Part 270—Nondiscrimination in the Outer Continental Shelf

Both BOEM and BSEE will have this part in its entirety.

TABLE J—DETAILED TABLE FOR PART 270

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 270.1 Purpose	Revised in both BSEE and BOEM § 570.1.	This section addresses the nondiscrimination on the OCS provisions that are relevant to the activities regulated by both BSEE and BOEM.
§ 270.2 Application of this part	Revised in both BSEE and BOEM § 570.2.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.
§ 270.3 Definitions	Revised in both BSEE and BOEM § 570.3.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.
§ 270.4 Discrimination prohibited ..	Revised in both BSEE and BOEM § 570.4.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.
§ 270.5 Complaint	Revised in both BSEE and BOEM § 570.5.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.
§ 270.6 Process	Revised in both BSEE and BOEM § 570.6.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.
§ 270.7 Remedies	Revised in both BSEE and BOEM § 570.7.	This section addresses the nondiscrimination on the OCS provisions that are under the authority of both BSEE and BOEM.

Part 280—Prospecting for Minerals Other Than Oil, Gas, and Sulphur on the Outer Continental Shelf—Moved to BOEM in Its Entirety, Chapter V, Part 580

BOEM is responsible for regulating prospecting activities or scientific research activities on the OCS related to hard minerals on unleased lands or on lands under lease to a third party.

TABLE K—DETAILED TABLE FOR PART 280

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General Information		
§ 280.1 What definitions apply to this part?	Moved to BOEM, § 580.1	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.2 What is the purpose of this part?	Moved to BOEM, § 580.2	This section addresses activities within the scope of oil, gas and sulphur prospecting on the OCS under BOEM.

TABLE K—DETAILED TABLE FOR PART 280—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 280.3 What requirements must I follow when I conduct prospecting or research activities?	Moved to BOEM, § 580.3	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.4 What activities are not covered by this part?	Moved to BOEM, § 580.4	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
Subpart B—How To Apply for a Permit or File a Notice		
§ 280.10 What must I do before I may conduct prospecting activities?	Moved to BOEM, § 580.10	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.11 What must I do before I may conduct scientific research?	Moved to BOEM, § 580.11	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.12 What must I include in my application or notification?	Moved to BOEM, § 580.12	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.13 Where must I send my application or notification?	Moved to BOEM, § 580.13	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
Subpart C—Obligations Under This Part		
§ 280.20 What must I not do in conducting Geological and Geophysical (G&G) prospecting or scientific research?	Moved to BOEM, § 580.20	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.21 What must I do in conducting G&G prospecting or scientific research?	Moved to BOEM, § 580.21	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.22 What must I do when seeking approval for modifications?	Moved to BOEM, § 580.22	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.23 How must I cooperate with inspection activities?	Moved to BOEM, § 580.23	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.24 What reports must I file?	Moved to BOEM, § 580.24	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.25 When may MMS require me to stop activities under this part?	Moved to BOEM, § 580.25	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.26 When may I resume activities?	Moved to BOEM, § 580.26	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.27 When may MMS cancel my permit?	In both BSEE and BOEM, § 580.27.	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.28 May I relinquish my permit?	In both BSEE and BOEM, § 580.28.	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.29 Will MMS monitor the environmental effects of my activity?	Moved to BOEM, § 580.29	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.30 What activities will not require environmental analysis?	Moved to BOEM, § 580.30	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.31 Whom will MMS notify about environmental issues?	Moved to BOEM, § 580.31	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.32 What penalties may I be subject to?	Moved to BOEM, § 580.32	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.33 How can I appeal a penalty?	Moved to BOEM, § 580.33	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.34 How can I appeal an order or decision?	Moved to BOEM, § 580.34	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
Subpart D—Data Requirements		
§ 280.40 When do I notify MMS that geological data and information are available for submission, inspection, and selection?	Moved to BOEM, § 580.40	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.41 What types of geological data and information must I submit to MMS?	Moved to BOEM, § 580.41	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.42 When geological data and information are obtained by a third party, what must we both do?	Moved to BOEM, § 580.42	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.

TABLE K—DETAILED TABLE FOR PART 280—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 280.50 When do I notify MMS that geophysical data and information are available for submission, inspection, and selection?	Moved to BOEM, § 580.50	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.51 What types of geophysical data and information must I submit to MMS?	Moved to BOEM, § 580.51	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.52 When geophysical data and information are obtained by a third party, what must we both do?	Moved to BOEM, § 580.52	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.60 Which of my costs will be reimbursed?	Moved to BOEM, § 580.60	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.61 Which of my costs will not be reimbursed?	Moved to BOEM, § 580.61	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.70 What data and information will be protected from public disclosure?	Moved to BOEM, § 580.70	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.71 What is the timetable for release of data and information?	Moved to BOEM, § 580.71	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.72 What procedure will MMS follow to disclose acquired data and information to a contractor for reproduction, processing, and interpretation?	Moved to BOEM, § 580.72	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
§ 280.73 Will MMS share data and information with coastal States?	Moved to BOEM, § 580.73	This section addresses activities within the scope of oil, gas, and sulphur prospecting on the OCS under BOEM.
Subpart E—Information Collection		
§ 280.80 Paperwork Reduction Act statement—information collection	Moved to BOEM, § 580.80	This section addresses activities within the scope of oil, gas and sulphur prospecting on the OCS under BOEM.

Part 281—Leasing of Minerals Other Than Oil, Gas, and Sulphur in the Outer Continental Shelf—Moved to BOEM in Its Entirety, Chapter V, Part 581

The Office of Natural Resources Revenue (ONRR) is the office that has the authority to determine the value for royalty purposes of minerals and other products produced on the OCS under Secretarial Order No. 3299. Because ONRR is responsible for valuation, technical corrections were made to this part to reflect that authority. This rule does not change the valuation authority possessed by ONRR or the procedures by which that authority is implemented. It merely revises the references in the regulations to conform to those in current Secretarial delegations. It has no effect on the rights, obligations, or interests of affected parties. It affects solely the organization, procedure, and practice of the agencies.

TABLE L—DETAILED TABLE FOR PART 281

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General		
§ 281.0 Authority for information collection.	Moved to BOEM, § 581.0	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.1 Purpose and applicability	Moved to BOEM, § 581.1	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.2 Authority	Moved to BOEM, § 581.2	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.3 Definitions	Moved to BOEM, § 581.3	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.4 Qualifications of lessees	Moved to BOEM, § 581.4	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.5 False statements	Moved to BOEM, § 581.5	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.6 Appeals	Moved to BOEM, § 581.6	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.7 Disclosure of information to the public.	Moved to BOEM, § 581.7	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.

TABLE L—DETAILED TABLE FOR PART 281—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 281.8 Rights to minerals	Moved to BOEM, § 581.8	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.9 Jurisdictional controversies.	Moved to BOEM, § 581.9	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
Subpart B—Leasing Procedures		
§ 281.11 Unsolicited request for a lease sale.	Moved to BOEM, § 581.11	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.12 Request for OCS mineral information and interest.	Moved to BOEM, § 581.12	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.13 Joint State/Federal coordination.	Moved to BOEM, § 581.13	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.14 OCS mining area identification.	Moved to BOEM, § 581.14	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.15 Tract size	Moved to BOEM, § 581.15	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.16 Proposed leasing notice	Moved to BOEM, § 581.16	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.17 Leasing notice	Moved to BOEM, § 581.17	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.18 Bidding system	Moved to BOEM, § 581.18	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.19 Lease term	Moved to BOEM, § 581.19	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.20 Submission of bids	Moved to BOEM, § 581.20	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.21 Award of leases	Moved to BOEM, § 581.21	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.22 Lease form	Moved to BOEM, § 581.22	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.23 Effective date of leases	Moved to BOEM, § 581.23	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
Subpart C—Financial Considerations		
§ 281.26 Payments	Moved to BOEM, § 581.26	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.27 Annual rental	Moved to BOEM, § 581.27	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.28 Royalty	Moved to BOEM, § 581.28	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.29 Royalty valuation	Moved to BOEM, § 581 29	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.30 Minimum royalty	Moved to BOEM, § 581.30	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.31 Overriding royalties	Moved to BOEM, § 581.31	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.32 Waiver, suspension, or reduction of rental, minimum royalty or production royalty.	Moved to BOEM, § 581.32	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.33 Bonds and bonding requirements.	Moved to BOEM, § 581.33	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
Subpart D—Assignments and Lease Extensions		
§ 281.40 Assignment of leases or interests therein.	Moved to BOEM, § 581.40	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.41 Requirements for filing for transfers.	Moved to BOEM, § 581.41	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.42 Effect of assignment on particular lease.	Moved to BOEM, § 581.42	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.43 Effect of suspensions on lease term.	Moved to BOEM, § 581.43	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
Subpart E—Termination of Leases		
§ 281.46 Relinquishment of leases or parts of leases.	Moved to BOEM, § 581.46	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.
§ 281.47 Cancellation of leases	Moved to BOEM, § 581.47	This section addresses activities within the scope of leasing of minerals other than oil, gas, and sulphur on the OCS under BOEM.

Part 282—Operations in the Outer Continental Shelf for Minerals Other Than Oil, Gas, and Sulphur

Both BOEM and BSEE have responsibilities for operations conducted under a mineral lease for OCS minerals other than oil, gas, or sulphur.

As stated previously, ONRR has the authority to determine the value for royalty purposes of minerals and other products produced on the OCS under Secretarial Order No. 3299. Because ONRR is the office responsible for valuation, technical corrections were made to this part to reflect that authority. This rule does not change the valuation authority possessed by ONRR or the procedures by which that authority is implemented. It merely revises the references in the regulations to conform to those in current Secretarial delegations. It has no effect on the rights, obligations, or interests of affected parties. It affects solely the organization, procedure, and practice of the agencies.

These responsibilities were divided between the bureaus as follows:

TABLE M—DETAILED TABLE FOR PART 282

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—General		
§ 282.0 Authority for information collection.	Both BSEE and BOEM § 582.0	Both agencies need the authority for information collection.
§ 282.1 Purpose and authority	Both BSEE and BOEM § 582.1	Needed by both agencies.
§ 282.2 Scope	Both BSEE and BOEM § 582.2	Needed by both agencies.
§ 282.3 Definitions	Both BSEE and BOEM § 582.3	Needed by both agencies.
§ 282.4 Opportunities for review and comment.	Moved to BOEM, § 582.4	BOEM responsibility.
§ 282.5 Disclosure of data and information to the public.	Both BSEE and BOEM § 582.5	Needed by both agencies.
§ 282.6 Disclosure of data and information to an adjacent State.	Both BSEE and BOEM § 582.6	Needed by both agencies.
§ 282.7 Jurisdictional controversies.	Both BSEE and BOEM § 582.7	Needed by both agencies.
Subpart B—Jurisdiction and Responsibilities of Director		
§ 282.10 Jurisdiction and responsibilities of Director.	Both BSEE and BOEM § 582.10 ...	Needed by both agencies.
§ 282.11 Director's authority	Moved to BOEM, § 582.11. Paragraph (d) on mining units is in both.	Paragraph (d) involves units, which is a BSEE function. Paragraph (d) also contains BOEM responsibilities as it mentions plans.
§ 282.12 Director's responsibilities	Responsibilities are shared by both BSEE and BOEM.	Paragraphs (a), (e), (f), and (h) are retained in BSEE. Paragraphs (a), (b), (c), (d) and (g) are in BOEM. This section contains, but is not limited to, general statements on the Director's responsibilities; language on mining plan approvals, delineation testing and lease operations; and conditions under which the Director may prescribe or approve departures.
§ 282.13 Suspension of production or other operations.	Retained in BSEE	Suspensions are under the authority of BSEE.
§ 282.14 Noncompliance, remedies, and penalties.	Both BSEE and BOEM § 582.14 ...	BSEE is responsible for addressing noncompliance, remedies, and penalties. Needed in both agencies.
§ 282.15 Cancellation of leases	Moved to BOEM, § 582.15	BOEM is responsible for lease administration.
Subpart C—Obligations and Responsibilities of Lessees		
§ 282.20 Obligations and responsibilities of lessees.	Moved to BOEM, § 582.20	This section addresses obligations and responsibilities of lessees that are the responsibility of BOEM.
§ 282.21 Plans, general	Moved to BOEM, § 582.21, except paragraph (e), which is in both.	This section addresses plans that are the responsibility of BOEM. Paragraph (e) addresses leasehold activities and how those activities must be carried out. Leasehold activities are generally operational in nature (*i.e.,* drilling, production) and therefore these responsibilities are also vested in BSEE.
§ 282.22 Delineation Plan	Moved to BOEM, § 582.22	This section addresses plans that are the responsibility of BOEM.
§ 282.23 Testing Plan	Moved to BOEM, § 582.23	This section addresses plans that are the responsibility of BOEM.
§ 282.24 Mining Plan	Moved to BOEM, § 582.24	This section addresses plans that are the responsibility of BOEM.
§ 282.25 Plan modification	Moved to BOEM, § 582.25	This section addresses plans that are the responsibility of BOEM.
§ 282.26 Contingency Plan	Moved to BOEM, § 582.26	This section addresses plans that are the responsibility of BOEM.
§ 282.27 Conduct of operations	Retained in BSEE. Paragraph (i) also in BOEM, § 582.27.	Paragraph (i) addresses plans that are the responsibility of BOEM.
§ 282.28 Environmental protection measures.	Moved to BOEM § 582.28. Paragraphs (c)(1), (c)(2), (c)(3), (c)(4) and (c)(6), and (d) are retained in BSEE. Paragraphs (c)(2) and (c)(6) are in both.	Paragraphs (c)(1), (c)(3) and (c)(4) pertain to mitigation, observations, and testing activities. Paragraph (d) describes ways to minimize environmental impacts. Overseeing these activities is a BSEE responsibility. Both BOEM and BSEE have discrete monitoring functions under (c)(2) and (c)(6).
§ 282.29 Reports and records	Moved to BOEM, § 582.29	A resource evaluation function under BOEM.
§ 282.30 Right of use and easement.	Moved to BOEM, § 582.30	BOEM has the authority to grant rights of use and easement.

TABLE M—DETAILED TABLE FOR PART 282—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
§ 282.31 Suspension of production or other operations.	Retained in BSEE	BSEE has the authority to suspend production or other operations.
Subpart D—Payments		
§ 282.40 Bonds	Moved to BOEM, § 582.40	Financial assurance is a BOEM function with a cross reference provided for BSEE.
§ 282.41 Method of royalty calculation.	Both BSEE and BOEM, § 582.41	ONRR regulations at 30 CFR part 1206 may apply. Otherwise, lessees must comply with BOEM's procedures specified in lease notices.
§ 282.42 Payments	Moved to BOEM, § 582.42	BOEM.
Subpart E—Appeals		
§ 282.50 Appeals	Both BSEE and BOEM, § 582.50	Both agencies need the procedures for addressing appeals.

Part 285—Renewable Energy Alternate Uses of Existing Facilities on the Outer Continental Shelf—Moved in Its Entirety to BOEM, Chapter V, Part 585

BOEM will manage the Renewable Energy Program for the near future. Once this program is more established and larger scale operations begin, it will be reorganized and a determination will be made regarding what functions will be distributed between the two bureaus; BSEE and BOEM.

Subchapter C—Appeals

Part 290—Appeals Procedures—Both BSEE and BOEM Will Have This Part in Its Entirety

TABLE N—DETAILED TABLE FOR PART 290

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Explanation
Subpart A—Offshore Minerals Management Appeal Procedures		
§ 290.1 What is the purpose of this subpart?	Both BSEE and BOEM § 590.1	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.2 Who may appeal?	Both BSEE and BOEM § 590.2	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.3 What is the time limit for filing an appeal?	Both BSEE and BOEM § 590.3	Both BSEE and BOEM. need to provide opportunity for appeals of decisions.
§ 290.4 How do I file an appeal?	Both BSEE and BOEM § 590.4	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.5 Can I obtain an extension for filing my Notice of Appeal?	Both BSEE and BOEM § 590.5	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.6 Are informal resolutions permitted?	Both BSEE and BOEM § 590.6	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.7 Do I have to comply with the decision or order while my appeal is pending?	Both BSEE and BOEM § 590.7	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
§ 290.8 How do I exhaust my administrative remedies?	Both BSEE and BOEM § 590.8	Both BSEE and BOEM need to provide opportunity for appeals of decisions.
Subpart B—[Reserved]		

Part 291—Open and Nondiscriminatory Access to Oil and Gas Pipelines Under the Outer Continental Shelf Lands Act—Retained by BSEE in Its Entirety

TABLE O—DETAILED TABLE FOR PART 291

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Justification
SUBCHAPTER C—APPEALS		
§ 291.1 What is MMS's authority to collect information?	Retained in its entirety in BSEE, chapter II.	This section addresses information collection authority for open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.

TABLE O—DETAILED TABLE FOR PART 291—Continued

Current citation and BSEE citation (if applicable)	Implementing bureau and BOEM citation (if applicable)	Justification
§ 291.100 What is the purpose of this part?	Retained in its entirety in BSEE, chapter II.	This section addresses purpose of open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.101 What definitions apply to this part?	Retained in its entirety in BSEE, chapter II.	This section addresses the definitions that pertain to open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.102 May I call the MMS Hotline to informally resolve an allegation that open and nondiscriminatory access was denied?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.103 May I use alternative dispute resolution to informally resolve an allegation that open and nondiscriminatory access was denied?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.104 Who may file a complaint or a third-party brief?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.105 What must a complaint contain?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.106 How do I file a complaint?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.107 How do I answer a complaint?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.108 How do I pay the processing fee?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.109 Can I ask for a fee waiver or a reduced processing fee?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.110 Who may MMS require to produce information?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.111 How does MMS treat the confidential information I provide?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.112 What process will MMS follow in rendering a decision on whether a grantee or transporter has provided open and nondiscriminatory access?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.113 What actions may MMS take to remedy denial of open and nondiscriminatory access?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.114 How do I appeal to the IBLA?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.
§ 291.115 How do I exhaust administrative remedies?	Retained in its entirety in BSEE, chapter II.	This section addresses open and nondiscriminatory access to oil and gas pipelines under OCSLA. Offshore operations are under the authority of BSEE.

Procedural Matters

Regulatory Planning and Review (Executive Order (E.O.) 12866)

This direct final rule is not a significant rule as determined by the Office of Management and Budget (OMB) and is not subject to review under E.O. 12866. This direct final rule reorganizes the title 30 CFR chapter II regulations; this rule does not change existing regulatory requirements.

(1) This direct final rule will not have an annual effect of $100 million or more on the economy. It will not adversely affect in a material way the economy, productivity, competition: jobs; the environment; public health or safety; or state, local, or Tribal governments or communities.

(2) This direct final rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency.

(3) This direct final rule will not alter the budgetary effects of entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

(4) This direct final rule will not raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in E.O. 12866.

Regulatory Flexibility Act

This direct final rule is exempt from the notice and comment provisions of

the Administrative Procedure Act (APA), 5 U.S.C. 553; therefore, the requirements of the Regulatory Flexibility Act do not apply, 5 U.S.C. 603(a).

Small Business Regulatory Enforcement Fairness Act

This direct final rule is not a major rule under the Small Business Regulatory Enforcement Fairness Act (5 U.S.C. 801 *et seq.*). This direct final rule:

a. Will not have an annual effect on the economy of $100 million or more.

b. Will not cause a major increase in costs or prices for consumers; individual industries; Federal, state, or local government agencies; or geographic regions.

c. Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

The requirements apply to all entities operating on the OCS. This direct final rule reorganizes the title 30 CFR chapter II regulations and does not change existing regulatory requirements.

Unfunded Mandates Reform Act of 1995

This direct final rule will not impose an unfunded mandate on state, local, or Tribal governments, or the private sector of more than $100 million per year. This direct final rule will not have a significant or unique effect on state, local, or Tribal governments, or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) is not required.

Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this direct final rule does not have significant takings implications. This direct final rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this direct final rule does not have federalism implications. This direct final rule will not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this direct final rule will not affect that role. A Federalism Assessment is not required.

Civil Justice Reform (E.O. 12988)

This direct final rule complies with the requirements of E.O. 12988. Specifically, this rule:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, we have evaluated this direct final rule and determined that it has no substantial effects on federally recognized Indian Tribes.

Paperwork Reduction Act (PRA) of 1995

This final rule does not contain new information collection requirements, and a submission to OMB is not required under 44 U.S.C. 3501 *et seq.* All information collections referred to in this rulemaking are in the 1010 numbering series and are unchanged.

National Environmental Policy Act of 1969

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. We evaluated this rule under the criteria of the National Environmental Policy Act, 43 CFR Part 46 and 516 Departmental Manual 15. This rule meets the criteria set forth in 43 CFR 46.210(i) in that this proposed rule is ''* * * of an administrative, financial, legal, technical, or procedural nature * * *.'' This rule also meets the criteria set forth in 516 Departmental Manual 15.4(C)(1) for a ''Categorical Exclusion'' in that its impacts are limited to administrative, economic or technological effects. Further, we have evaluated this proposed rule to determine if it involves any of the extraordinary circumstances that would require an environmental assessment or an environmental impact statement as set forth in 43 CFR 46.215. We concluded that this rule does not meet any of the criteria for extraordinary circumstances as set forth therein.

Data Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C section 515, 114 Stat. 2763, 2763A–153–154).

Effects of the Nation's Energy Supply (E.O. 13211)

This direct final rule is not a significant energy action under the definition in E.O. 13211. A Statement of Energy Effects is not required.

List of Subjects

30 CFR Part 203

Continental shelf, Government contracts, Indians—lands, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Sulphur.

30 CFR Part 250

Administrative practice and procedure, Continental shelf, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 251

Continental shelf, Freedom of information, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements, Research.

30 CFR Part 252

Continental shelf, Freedom of information, Intergovernmental relations, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 254

Continental shelf, Intergovernmental relations, Oil and gas exploration, Oil pollution, Pipelines, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 256

Administrative practice and procedure, Continental shelf, Environmental protection, Government contracts, Intergovernmental relations, Oil and gas exploration, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 270

Administrative practice and procedure, Civil rights, Continental shelf, Government contracts, Oil and gas exploration, Public lands—mineral resources.

30 CFR Part 282

Administrative practice and procedure, Continental shelf, Environmental protection, Government contracts, Intergovernmental relations, Mineral royalties, Penalties, Public lands—mineral resources, Reporting

and recordkeeping requirements, Surety bonds.

30 CFR Part 290

Administrative practice and procedure.

30 CFR Part 291

Administrative practice and procedure.

30 CFR Part 519

Continental shelf, Government contracts, Indians—lands, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Sulphur.

30 CFR Part 550

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Investigations, Oil and gas exploration, Penalties, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur.

30 CFR Part 551

Continental shelf, Freedom of information, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements, Research.

30 CFR Part 552

Continental shelf, Freedom of information, Intergovernmental relations, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 553

Continental shelf, Environmental protection, Intergovernmental relations, Oil and gas exploration, Oil pollution, Penalties, Pipelines, Public lands—mineral resources, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 556

Administrative practice and procedure, Continental shelf, Environmental protection, Government contracts, Intergovernmental relations, Oil and gas exploration, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 559

Continental shelf, Government contracts, Mineral royalties, Oil and gas exploration, Public lands—mineral resources.

30 CFR Part 560

Continental shelf, Government contracts, Mineral royalties, Oil and gas exploration, Public lands—mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 570

Administrative practice and procedure, Civil rights, Continental shelf, Government contracts, Oil and gas exploration, Public lands—mineral resources.

30 CFR Part 580

Continental shelf, Public lands—mineral resources, Reporting and recordkeeping requirements, Research.

30 CFR Part 581

Administrative practice and procedure, Continental shelf, Government contracts, Intergovernmental relations, Mineral royalties, Public lands—mineral resources, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 582

Administrative practice and procedure, Continental shelf, Environmental protection, Government contracts, Intergovernmental relations, Mineral royalties, Penalties, Public lands—mineral resources, Reporting and recordkeeping requirements, Surety bonds.

30 CFR Part 585

Continental shelf, Environmental protection, Incorporation by reference, Public lands.

30 CFR Part 590

Administrative practice and procedure.

Dated: August 18, 2011.

Ned Farquhar,

Deputy Assistant Secretary—Land and Minerals Management.

For the reasons stated in the preamble, under the authority of 5 U.S.C. 901 *et seq.,* the Bureau of Safety and Environmental Enforcement (BSEE) reassigns chapter II and Bureau of Ocean Energy Management (BOEM) establishes chapter V as follows:

TITLE 30—MINERAL RESOURCES

■ 1. Chapter II is revised to read as follows:

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

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

Part
203 RELIEF OR REDUCTION IN ROYALTY RATES
219 RESERVED

SUBCHAPTER B—OFFSHORE

250 OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF
251 GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF
252 OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM
253 RESERVED
254 OIL–SPILL RESPONSE REQUIREMENTS FOR FACILITIES LOCATED SEAWARD OF THE COAST LINE
256 LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF
259 RESERVED
260 RESERVED
270 NONDISCRIMINATION IN THE OUTER CONTINENTAL SHELF
280 RESERVED
281 RESERVED
282 OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR
285 RESERVED

SUBCHAPTER C—APPEALS

290 APPEAL PROCEDURES
291 OPEN AND NONDISCRIMINATORY ACCESS TO OIL AND GAS PIPELINES UNDER THE OUTER CONTINENTAL SHELF LANDS ACT

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

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.*

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).
(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 *Pay.gov* Web site and you must include a copy of the *Pay.gov* confirmation receipt page with your application or assessment. The *Pay.gov* Web site may be accessed through a link on the BSEE Offshore Web site at: *http://www.bsee.gov/offshore/* homepage or directly through *Pay.gov* at: *https://www.pay.gov/paygov/.*

§ 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 1010–0071. 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, 381 Elden Street, Herndon, VA 20170.

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.
(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.

A price threshold in year 2007 dollars of . . .	Applies to . . .
(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.
(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.

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:—
(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.

If . . .	Then . . .	And . . .
(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.
(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			

Required reports	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(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, 381 Elden Street, Herndon, VA 20170.

§ 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).

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Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

PART 219—[RESERVED]

Subchapter B—Offshore

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

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250.1927 What happens if BSEE finds shortcomings in my SEMS program?
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Authority: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

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.

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.

§ 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.

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.

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.

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.

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.

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.

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.

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; and

(2) Maintaining all equipment and work areas in a safe condition.

(b) You must immediately control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) You must use the best available and safest technology (BAST) whenever practical on all exploration, development, and production operations. In general, we consider your compliance with BSEE regulations to be the use of BAST.

(d) The Director may require additional measures to ensure the use of BAST:

(1) To avoid the failure of equipment that would have a significant effect on safety, health, or the environment;

(2) If it is economically feasible; and

(3) If the benefits outweigh the costs.

§ 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 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, 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.

§§ 250.115–250.117 [Reserved]

§ 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) [Reserved]		
(2) [Reserved]		
(3) Suspension of Operations/Suspension of Production (SOO/SOP) Request.	$1,968	§ 250.171(e).
(4) [Reserved]		
(5) [Reserved]		
(6) Deepwater Operations Plan	$3,336	§ 250.292(p).
(7) [Reserved]		
(8) Application for Permit to Drill (APD; Form BSEE–0123)	$1,959 for initial applications only; no fee for revisions.	§ 250.410(d); § 250.513(b); § 250.515; § 250.1605; § 250.1617(a); § 250.1622.
(9) Application for Permit to Modify (APM; Form BSEE–0124)	$116	§ 250.460; § 250.513(b); § 250.613(b); 250.1618(a); § 250.1622; § 250.1704(g).
(10) New Facility Production Safety System Application for facility with more than 125 components.	$5,030 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); $13,238 additional fee will be charged if BSEE deems it necessary to visit a facility offshore, and $6,884 to visit a facility in a shipyard.	§ 250.802(e).
(11) New Facility Production Safety System Application for facility with 25–125 components.	$1,218 Additional fee of $8,313 will be charged if BSEE deems it necessary to visit a facility offshore, and $4,766 to visit a facility in a shipyard.	§ 250.802(e).
(12) New Facility Production Safety System Application for facility with fewer than 25 components.	$604	§ 250.802(e).
(13) Production Safety System Application—Modification with more than 125 components reviewed.	$561	§ 250.802(e).
(14) Production Safety System Application—Modification with 25–125 components reviewed.	$201	§ 250.802(e).
(15) Production Safety System Application—Modification with fewer than 25 components reviewed.	$85	§ 250.802(e).
(16) Platform Application—Installation—Under the Platform Verification Program.	$21,075	§ 250.905(l).
(17) Platform Application—Installation—Fixed Structure Under the Platform Approval Program.	$3,018	§ 250.905(l).
(18) Platform Application—Installation—Caisson/Well Protector	$1,536	§ 250.905(l)
(19) Platform Application—Modification/Repair	$3,601	§ 250.905(l).
(20) New Pipeline Application (Lease Term)	$3,283	§ 250.1000(b).
(21) Pipeline Application—Modification (Lease Term)	$1,906	§ 250.1000(b).
(22) Pipeline Application—Modification (ROW)	$3,865	§ 250.1000(b).
(23) Pipeline Repair Notification	$360	§ 250.1008(e).
(24) Pipeline Right-of-Way (ROW) Grant Application	$2,569	§ 250.1015(a).
(25) Pipeline Conversion of Lease Term to ROW	$219	§ 250.1015(a).
(26) Pipeline ROW Assignment	$186	§ 250.1018(b).
(27) 500 Feet From Lease/Unit Line Production Request	$3,608	§ 250.1156(a).
(28) Gas Cap Production Request	$4,592	§ 250.1157.
(29) Downhole Commingling Request	$5,357	§ 250.1158(a).
(30) Complex Surface Commingling and Measurement Application	$3,760	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(31) Simple Surface Commingling and Measurement Application	$1,271	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(32) Voluntary Unitization Proposal or Unit Expansion	$11,698	§ 250.1303(d).
(33) Unitization Revision	$831	§ 250.1303(d).
(34) Application to Remove a Platform or Other Facility	$4,342	§ 250.1727.
(35) Application to Decommission a Pipeline (Lease Term)	$1,059	§ 250.1751(a) or § 250.1752(a).
(36) Application to Decommission a Pipeline (ROW)	$2,012	§ 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.

§ 250.126 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 a link on the BSEE Offshore Web site at: *http://www.bsee.gov/offshore/* homepage or directly through *Pay.gov* at: *https://www.pay.gov/paygov/.*

(a) If you submitted an application through eWell, you must use the interactive payment feature in that system, which directs you through *Pay.gov.*

(b) For applications not submitted electronically through eWell, 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.

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 [Reserved]

§ 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 180-day 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.

§ 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 180 days of the primary term, and whenever production resumes during the last 180 days 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 180 days 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 180th day 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 180th day after you stop operations.

(e) You may ask the Regional Supervisor to allow you more than 180 days to resume operations on a lease continued beyond its primary term when operating conditions warrant. The request must be in writing and explain the operating conditions that warrant a longer period. In allowing additional time, the Regional Supervisor must determine that the longer period is in the National interest, and 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 180-day period after having ceased, or whenever drilling or well-reworking operations begin before the end of the 180-day 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 180-day period.

§§ 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.

§ 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 apparent violations.

Any person may report to BSEE an apparent violation or failure to comply with any provision of the Act, any provision of a lease, license, or permit issued under the Act, or any provision of any regulation or order issued under the Act. When BSEE receives a report of an apparent violation, or when a BSEE employee detects an apparent violation after making an initial determination of the validity, BSEE will investigate according to BSEE procedures.

§ 250.194 How must I protect archaeological resources?

(a) [Reserved]

(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.
(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.

If . . .	BSEE 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 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.

(a) The BSEE is incorporating by reference the documents listed in paragraphs (e) through (k) of this section. Paragraphs (e) through (k) identify the publishing organization of the documents, the address and phone number where you may obtain these documents, and the documents incorporated by reference. The Director of the Federal Register has approved the incorporations by reference according to 5 U.S.C. 552(a) and 1 CFR part 51.

(1) Incorporation by reference of a document is limited to the edition of the publication that is cited in this section. Future amendments or revisions of the document are not included. The BSEE will publish any changes to a document in the **Federal Register** and amend this section.

(2) The BSEE may make the rule amending the document effective without prior opportunity for public comment when BSEE determines:

(i) 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

(ii) The BSEE meets the requirements for making a rule immediately effective under 5 U.S.C. 553.

(3) 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 incorporates all of a document, you are responsible for complying with the provisions of that entire document, except to the extent that section provides otherwise. When a section in this part incorporates part of a document, you are responsible for complying with that part of the document as provided in that section. If any incorporated document uses the word *should,* it means *must* for purposes of these regulations.

(b) The BSEE incorporated each document or specific portion by reference in the sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections in this part calls for compliance with specific portions of

the listed documents. In each instance, the applicable document is the specific edition or specific edition and supplement or addendum cited in this section.

(c) 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 the prior written approval for alternative compliance from the authorized BSEE official.

(d) You may inspect these documents at the Bureau of Safety and Environmental Enforcement, 381 Elden Street, Room 3313, Herndon, Virginia 20170; phone: 703–787–1587; 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.htm.*

(e) American Concrete Institute (ACI), ACI Standards, P. O. Box 9094, Farmington Hill, MI 48333–9094: *http://www.concrete.org;* phone: 248–848–3700:

(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95), incorporated by reference at § 250.901.

(2) ACI 318R–95, Commentary on Building Code Requirements for Reinforced Concrete, 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.

(f) 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]

(g) American National Standards Institute (ANSI), ANSI/ASME Codes, ATTN: Sales Department, 25 West 43rd Street, 4th Floor, New York, NY 10036; *http://www.ansi.org;* phone: 212–642–4900; and/or American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007–2900; *http://www.asme.org;* phone: 973–882–5155:

(1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at § 250.803 and § 250.1629;

(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at §§ 250.803 and 250.1629;

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1 and 2, and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at §§ 250.803 and 250.1629;

(4) ANSI/ASME B 16.5–2003, Pipe Flanges and Flanged Fittings incorporated by reference at § 250.1002;

(5) ANSI/ASME B 31.8–2003, Gas Transmission and Distribution Piping Systems incorporated by reference at § 250.1002;

(6) ANSI/ASME SPPE–1–1994, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations, incorporated by reference at § 250.806;

(7) ANSI/ASME SPPE–1d–1996 Addenda, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations, incorporated by reference at § 250.806;

(8) ANSI Z88.2–1992, American National Standard for Respiratory Protection, incorporated by reference at, § 250.490.

(h) 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, Downstream Segment, Ninth Edition, June 2006; incorporated by reference at §§ 250.803 and 250.1629;

(2) API Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at § 250.901;

(3) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at § 250.901;

(4) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, May 2007; incorporated by reference at § 250.901;

(5) API MPMS, Chapter 1—Vocabulary, Second Edition, July 1994; incorporated by reference at § 250.1201;

(6) 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 February 2007; incorporated by reference at § 250.1202;

(7) API MPMS, Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; reaffirmed, December 2007; incorporated by reference at § 250.1202;

(8) 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;

(9) 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, October 2006; incorporated by reference at § 250.1202;

(10) API MPMS, Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005; incorporated by reference at § 250.1202;

(11) API MPMS, Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003; incorporated by reference at § 250.1202;

(12) API MPMS, Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, reaffirmed November 2005; incorporated by reference at § 250.1202;

(13) API MPMS, Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, reaffirmed: August 2005; incorporated by reference at § 250.1202;

(14) API MPMS, Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, May 1999; reaffirmed 2003; incorporated by reference at § 250.1202;

(15) API MPMS, Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed 2003; incorporated by reference at § 250.1202;

(16) API MPMS, Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Fourth Edition, September 2005; incorporated by reference at § 250.1202;

(17) API MPMS, Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005; incorporated by reference at § 250.1202;

(18) API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005; incorporated by reference at § 250.1202;

(19) API MPMS, Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005; incorporated by reference at § 250.1202;

(20) API MPMS, Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005; incorporated by reference at § 250.1202;

(21) API MPMS, Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed, April 2007; incorporated by reference at § 250.1202;

(22) API MPMS, Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed, February 2007; incorporated by reference at § 250.1202;

(23) API MPMS, Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed, April 2007; incorporated by reference at § 250.1202;

(24) API MPMS, Chapter 7—Temperature Determination, First Edition, June 2001; reaffirmed, March 2007; incorporated by reference at § 250.1202;

(25) 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;

(26) 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;

(27) 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)(3) and (l)(4);

(28) 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;

(29) 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; incorporated by reference at § 250.1202;

(30) 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;

(31) 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;

(32) 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;

(33) 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;

(34) 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;

(35) 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;

(36) 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;

(37) 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 2002; incorporated by reference at § 250.1202;

(38) 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; incorporated by reference at § 250.1202;

(39) 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;

(40) 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;

(41) 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;

(42) 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; incorporated by reference at § 250.1203;

(43) 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;

(44) 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;

(45) API MPMS, Chapter 20—Section 1—Allocation Measurement, First Edition, September 1993; reaffirmed October 2006; incorporated by reference at § 250.1202;

(46) 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;

(47) 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;

(48) API RP 2D, Operation and Maintenance of Offshore Cranes, Sixth Edition, May 2007; incorporated by reference at § 250.108;

(49) API RP 2FPS, RP for Planning, Designing, and Constructing Floating Production Systems; First Edition, March 2001; incorporated by reference at § 250.901;

(50) 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);

(51) 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 §§ 250.800; 250.901 and 250.1002;

(52) API RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008; incorporated by reference at §§ 250.800 and 250.901;

(53) 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 § 250.901;

(54) API RP 2T, Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997; incorporated by reference at § 250.901;

(55) API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress; incorporated by reference at §§ 250.801 and 250.804;

(56) 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, 250.292, 250.802, 250.803, 250.804, 250.1002, 250.1004, 250.1628, 250.1629, and 250.1630;

(57) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; reaffirmed, March 2007; incorporated by reference at §§ 250.802 and 250.1628;

(58) API RP 14F, Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, Fifth Edition, July 2008; incorporated by reference at §§ 250.114, 250.803, and 250.1629;

(59) 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, First Edition, September 2001, reaffirmed: March 2007; incorporated by reference at §§ 250.114, 250.803, and 250.1629;

(60) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; incorporated by reference at §§ 250.803 and 250.1629;

(61) API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007; incorporated by reference at §§ 250.802 and 250.804;

(62) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; reaffirmed: March 2007; incorporated by reference at §§ 250.800 and 250.901;

(63) API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004; incorporated by reference at §§ 250.442, 250.446, 250.516, and 250.617,

(64) API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deepwater Wells, First Edition, September 2002; incorporated by reference at § 250.415;

(65) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; reaffirmed November 2002; incorporated by reference at §§ 250.114, 250.459, 250.802, 250.803, 250.1628, and 250.1629;

(66) 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 November 2002; incorporated by reference at §§ 250.114, 250.459, 250.802, 250.803, 250.1628, and 250.1629;

(67) API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003; incorporated by reference at § 250.1202;

(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008; incorporated by reference at § 250.806;

(69) API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004; incorporated by reference at § 250.108;

(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; incorporated by reference at §§ 250.806 and 250.1002;

(71) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003; incorporated by reference at § 250.806;

(72) 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;

(73) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Effective Date: May 1,

2006; also available as ISO 10432:2004; incorporated by reference at § 250.806;

(74) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008; Effective Date: January 1, 2009, Contains API Monogram Annex as Part of U.S. National Adoption; ISO 13628–2:2006 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 2: Unbonded flexible pipe systems for subsea and marine application; incorporated by reference at §§ 250.803, 250.1002, and 250.1007;

(75) API Standard 2551, Measurement and Calibration of Horizontal Tanks, First Edition, 1965; reaffirmed March 2002; incorporated by reference at § 250.1202;

(76) 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;

(77) API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; incorporated by reference at § 250.1202.

(78) API RP 90, Annular Casing Pressure Management for Offshore Wells, First Edition, August 2006, incorporated by reference at § 250.518.

(79) API RP 65–Part 2, Isolating Potential Flow Zones During Well Construction; First Edition, May 2010; incorporated by reference at § 250.415.

(80) 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.

(i) 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: 610–832–9500:

(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;

(j) American Welding Society (AWS), AWS Codes, 550 NW, LeJeune Road, 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.

(k) National Association of Corrosion Engineers (NACE), NACE Standards, 1440 South Creek Drive, 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 §§ 250.901 and 250.490;

(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.

§ 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, 381 Elden Street, Herndon, VA 20170.

(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.)	Reasons for collecting information and how used
(1) Subpart A, General (1010–0114), including Forms BSEE–0132, Evacuation Statistics; BSEE–0143, Facility/Equipment Damage Report; BSEE–1832, Notification of Incidents of Noncompliance.	To inform BSEE 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 exploration, development, and production on OCS leases. To support the unproved and proved reserve estimation, resource assessment, and fair market value determinations. To allow BSEE to rapidly assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.

30 CFR subpart, title and/or BSEE Form (OMB Control No.)	Reasons for collecting information and how used
(2) Subpart B, Exploration and Development and Production Plans (1010–0151).	To inform BSEE, 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 BSEE of measures to be taken to prevent water pollution. To ensure that appropriate measures are taken to prevent water pollution.
(4) Subpart D, Oil and Gas and Drilling Operations (1010–0141), including Forms BSEE–0123, Application for Permit to Drill; BSEE–0123S, Supplemental APD Information Sheet; BSEE–0124, Application for Permit to Modify; BSEE–0125, End of Operations Report; BSEE–0133, Well Activity Report; BSEE–0133S, Open Hole Data Report; and BSEE–144, Rig Movement Notification Report.	To inform BSEE of the equipment and procedures to be used in drilling operations on the OCS. To ensure that drilling operations are safe and protect the human, marine, and coastal environment.
(5) Subpart E, Oil and Gas Well-Completion Operations (1010–0067) ..	To inform BSEE of the equipment and procedures to be used in well-completion operations on the OCS. To ensure that well-completion operations are safe and protect the human, marine, and coastal environment.
(6) Subpart F, Oil and Gas Well Workover Operations (1010–0043)	To inform BSEE of the equipment and procedures to be used during well-workover operations on the OCS. To ensure that well-workover operations are safe and protect the human, marine, and coastal environment.
(7) Subpart H, Oil and Gas Production Safety Systems (1010–0059)	To inform BSEE of the equipment and procedures to be used during production operations on the OCS. To ensure that production operations are safe and protect the human, marine, and coastal environment.
(8) Subpart I, Platforms and Structures (1010–0149)	To provide BSEE with information regarding the design, fabrication, and installation of platforms on the OCS. To ensure the structural integrity of platforms installed on the OCS.
(9) Subpart J, Pipelines and Pipeline Rights-of-Way (1010–0050), including Form BSEE–0149, Assignment of Federal OCS Pipeline Right-of-Way Grant.	To provide BSEE 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.
(10) Subpart K, Oil and Gas Production Rates (1010–0041), including Forms BSEE–0126, Well Potential Test Report and BSEE–0128, Semiannual Well Test Report.	To inform BSEE of production rates for hydrocarbons produced on the OCS. To ensure economic maximization of ultimate hydrocarbon recovery
(11) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1010–0051).	To inform BSEE of the measurement of production, commingling of hydrocarbons, and site security plans. To ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security is maintained.
(12) Subpart M, Unitization (1010–0068)	To inform BSEE of the unitization of leases. To ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(13) 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.
(14) Subpart O, Well Control and Production Safety Training (1010–0128).	To inform BSEE of training program curricula, course schedules, and attendance. To ensure that training programs are technically accurate and sufficient to meet safety and environmental requirements, and that workers are properly trained to operate on the OCS.
(15) Subpart P, Sulphur Operations (1010–0086)	To inform BSEE of sulphur exploration and development operations on the OCS. To ensure that OCS sulphur operations are safe; protect the human, marine, and coastal environment; and will result in diligent exploration, development, and production of sulphur leases.
(16) Subpart Q, Decommissioning Activities (1010–0142)	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.
(17) Subpart S, Safety and Environmental Management Systems (1010–0186), including Form BSEE–0131, Performance Measures Data.	The SEMS program will describe management commitment to safety and the environment, as well as policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel). The information collected is the form to gather the raw Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.

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 [Reserved]

§ 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; and

(p) Payment of the service fee listed in § 250.125.

§ 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 which could cause unreasonable degradation to the marine environment. No petroleum-based substances, including diesel fuel, may be added to the drilling mud system without prior approval of the District Manager.

(2) Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Manager.

(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.

§ 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 Who is subject to the requirements of this subpart?

The requirements of this subpart apply to lessees, operating rights owners, operators, and their contractors and subcontractors.

§ 250.401 What must I do to keep wells under control?

You must take necessary precautions to keep wells under control at all times. You must:

(a) Use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during drilling operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling 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 subpart O; and

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment.

§ 250.402 When and how must I secure a well?

Whenever you interrupt drilling operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the device at an appropriate depth within a properly cemented casing string or liner.

(a) Among the events that may cause you to interrupt drilling operations are:

(1) Evacuation of the drilling crew;

(2) Inability to keep the drilling rig on location; or

(3) Repair to major drilling or well-control equipment.

(b) For floating drilling operations, the District Manager may approve the use of blind or blind-shear rams or pipe rams and an inside BOP if you don't have time to install a downhole safety device or if special circumstances occur.

§ 250.403 What drilling unit movements must I report?

(a) You must report the movement of all drilling units on and off drilling

locations to the District Manager. This includes both MODU and platform rigs. You must inform the District Manager 24 hours before:

(1) The arrival of an MODU on location;

(2) The movement of a platform rig to a platform;

(3) The movement of a platform rig to another slot;

(4) The movement of an MODU to another slot; and

(5) The departure of an MODU 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) In the Gulf of Mexico OCS Region, you must report drilling unit movements on form BSEE–0144, Rig Movement Notification Report.

§ 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 take 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.

§ 250.406 What additional safety measures must I take when I conduct drilling operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct drilling operations on a platform with producing wells or that has other hydrocarbon flow:

(a) You must install an emergency shutdown station near the driller's console;

(b) You must shut in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a drilling rig 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 drilling unit between wells on a platform;

(3) A mobile offshore drilling unit (MODU) moves within 500 feet of a platform. You may resume production once the MODU is in place, secured, and ready to begin drilling operations.

§ 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 described in the following table.

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 and BOP systems descriptions.	§ 250.416
(f) Requirements for using an MODU.	§ 250.417
(g) Additional information	§ 250.418

§ 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 estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, 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.

§ 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 between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by § 250.413(g);

(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 alternative procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternative procedures afford an equal or greater degree of protection, safety, or performance, or why you need the departures; and

(i) Projected plans for well testing (refer to § 250.460 for safety requirements).

§ 250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

(a) Hole sizes and casing sizes, including: weights; grades; collapse, and burst values; types of connection; and setting depths (measured and true vertical depth (TVD));

(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 RP 65–Part 2, Isolating Potential Flow Zones During Well Construction (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 RP 65–Part 2, Sections 3 and 4).

§ 250.416 What must I include in the diverter and BOP descriptions?

You must include in the diverter and BOP descriptions:

(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 annular BOP 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;

(c) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(d) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

(e) Independent third party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe in the hole under maximum anticipated surface pressure. The documentation must include test results and calculations of shearing capacity of all pipe to be used in the well including correction for MASP;

(f) When you use a subsea BOP stack, independent third party verification that shows:

(1) The BOP stack is designed for the specific equipment on the rig and for the specific well design;

(2) The BOP stack has not been compromised or damaged from previous service;

(3) The BOP stack will operate in the conditions in which it will be used; and

(g) The qualifications of the independent third party referenced in paragraphs (e) and (f) of this section:

(1) The independent third party in paragraph (e) in this section must be a technical classification society; an API-licensed manufacturing, inspection, or certification firm; or a licensed professional engineering firm capable of providing the verifications required under this part. The independent third party must not be the original equipment manufacturer (OEM).

(2) You must:

(i) Include evidence that the firm you are using is reputable, the firm or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, the firm carries industry-standard levels of professional liability insurance, and the firm has no record of violations of applicable law.

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information

submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the District Manager at least 24 hours in advance.

§ 250.417 What must I provide if I plan to use a mobile offshore drilling unit (MODU)?

If you plan to use a MODU, you must provide:

(a) *Fitness requirements.* You must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location. This information must include the maximum environmental and operational conditions that the unit 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, the District Manager may approve your APD but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD if information collected during operations show that the drilling unit is not capable of performing at the proposed location.

(b) *Foundation requirements.* You must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed drilling unit. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD if additional information is needed to make a determination that the conditions are capable of supporting the drilling unit.

(c) *Frontier areas.* (1) If the design of the drilling unit 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 unit's design. If required, you must obtain the third-party review according to §§ 250.915 through 250.918. You may submit this information before submitting an APD.

(2) If you plan to drill in a frontier area, you must have a contingency plan that addresses design and operating limitations of the drilling unit. 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 drilling or rig 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) *U.S. Coast Guard (USCG) documentation.* You must provide the current Certificate of Inspection or Letter of Compliance from the USCG. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Floating drilling unit.* If you use a floating drilling unit, you must indicate that you have a contingency plan for moving off location in an emergency situation.

(f) *Inspection of unit.* The drilling unit must be available for inspection by the District Manager before commencing operations.

(g) Once the District Manager has approved a MODU for use, you do not need to re-submit the information required by this section for another APD to use the same MODU unless changes in equipment affect its rated capacity to operate in the District.

§ 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 some cement to facilitate casing removal upon well abandonment;

(h) Certification of your casing and cementing program as required in § 250.420(a)(6);

(i) Description of qualifications required by § 250.416(f) of any independent third party; and

(j) Such other information as the District Manager may require.

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 requirements of this section and of §§ 250.421 through 250.428.

(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; and

(6) Include certification signed by a Registered Professional Engineer that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during well completion activities and that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions. The Registered Professional Engineer must be registered in a State in the United States. Submit this certification with your APD (Form BSEE–0123).

(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) For the final casing string (or liner if it is your final string), you must install dual mechanical barriers in addition to cement, to prevent flow in the event of a failure in the cement. These may include dual float valves, or one float valve and a mechanical barrier. You must submit documentation to BSEE 30 days after installation of the dual mechanical barriers.

(c) *Cementing requirements.* 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 of the casing or before commencing completion operations.

§ 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.
(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.	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 glory hole, 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 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 above the casing shoe and 500 feet 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 above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet 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 above the previous casing shoe.	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.

§ 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 pressure testing casing?

(a) The table in this section describes the minimum test pressures for each string of casing. You may not resume drilling or other down-hole 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 re-cement, repair the casing, or run additional casing to provide a proper seal. The District Manager may approve or require other casing test pressures.

Casing type	Minimum test pressure
(1) Drive or Structural	Not required.
(2) Conductor	200 psi.
(3) Surface, Intermediate, and Production	70 percent of its minimum internal yield.

(b) You must ensure proper installation of casing or liner in the subsea wellhead or liner hanger.

(1) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string or liner.

(2) 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 liner.

(3) You must submit for approval with your APD, test procedures and criteria for a successful test.

(4) You must document all your test results and make them available to BSEE upon request.

(c) You must perform a negative pressure test on all wells to ensure proper casing installation. You must perform this test for the intermediate and production casing strings.

(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.

§ 250.424 What are the requirements for prolonged drilling operations?

If wellbore operations continue for more than 30 days within a casing string run to the surface:

(a) You must stop drilling operations as soon as practicable, and evaluate the effects of the prolonged operations on continued drilling operations and the life of the well. At a minimum, you must:

(1) Caliper or pressure test the casing; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations.

(b) If casing integrity has deteriorated to a level below minimum safety factors, you must:

(1) Repair the casing or run another casing string; and

(2) Obtain approval from the District Manager before you begin repairs.

§ 250.425 What are the requirements for pressure testing liners?

(a) You must test each drilling liner (and liner-lap) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Manager may approve or require other liner test pressures.

(b) You must test each production liner (and liner-lap) to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(c) You may not resume drilling or other down-hole 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 re-cement, repair the liner, or run additional casing/liner to provide a proper seal.

§ 250.426 What are the recordkeeping requirements for casing and liner pressure tests?

You must record the time, date, and results of each pressure test in the driller's report maintained under standard industry practice. In addition, you must record each test on a pressure chart and have your onsite representative sign and date the test as being correct.

§ 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 the approved APD. When you cannot maintain this safe margin, you must suspend drilling operations and remedy the situation.

§ 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 increase casing setting depths 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.
(c) Have indication of inadequate cement job (such as lost returns, cement channeling, or failure of equipment),	(1) Pressure test the casing shoe; (2) Run a temperature survey; (3) Run a cement bond log; or (4) Use a combination of these techniques.
(d) Inadequate cement job,	Re-cement or take other remedial actions as approved by the District Manager.
(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.

If you encounter the following situation:	Then you must . . .
(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.

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.

(c) You must alternate actuations and tests between control stations.

§ 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.

Blowout Preventer (BOP) System Requirements

§ 250.440 What are the general requirements for BOP systems and system components?

You must design, install, maintain, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. The BOP system includes the BOP stack and associated BOP systems and equipment.

§ 250.441 What are the requirements for a surface BOP stack?

(a) When you drill with a surface BOP stack, you must install the BOP system before drilling below surface casing. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind or blind-shear rams.

(b) Your surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing the drill pipe that is in the hole.

(c) You must install an accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components. The system must perform with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. 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.

(d) In addition to the stack and accumulator system, you must install the associated BOP systems and equipment required by the regulations in this subpart.

§ 250.442 What are the requirements for a subsea BOP system?

When you drill with a subsea BOP system, you must install the BOP system before drilling below the surface casing. The District Manager may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need. The table in this paragraph outlines your requirements.

When drilling with a subsea BOP system, you must:	Additional requirements
(a) Have at least four remote-controlled, hydraulically operated BOPs ..	You must have at least one annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures.
(b) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system.	
(c) Have an accumulator system to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface.	The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). The District Manager may approve a suitable alternate method.
(d) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability.	At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind-shear rams and unlatching the LMRP.
(e) Maintain an ROV and have a trained ROV crew on each floating drilling rig on a continuous basis. The crew must examine all ROV related well control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well 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.
(f) Provide autoshear and deadman systems for dynamically positioned rigs.	(1) *Autoshear system* means a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP. When the autoshear is armed, a disconnect of the LMRP closes the shear rams. This is considered a ''rapid discharge'' system. (2) *Deadman System* means a safety system that is designed to automatically close 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. (3) You may also have an acoustic system.
(g) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions.	Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.
(h) Clearly label all control panels for the subsea BOP system	Label other BOP control panels such as hydraulic control panel.
(i) 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.
(j) Establish minimum requirements for personnel authorized to operate critical BOP equipment.	Personnel must have: (1) Training in deepwater well control theory and practice according to the requirements of 30 CFR 250, subpart O; and (2) A comprehensive knowledge of BOP hardware and control systems.
(k) 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.
(l) Install the BOP stack in a glory hole when in ice-scour area	Your glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

§ 250.443 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 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.

(b) At least two BOP control stations. One station must be on the drilling floor. You must locate the other station in a readily accessible location away from the drilling floor.

(c) Side outlets on the BOP stack for separate kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets.

(d) A choke and a kill line on the BOP stack. You must equip each line with two full-opening valves, one of which must be remote-controlled. For a subsea BOP system, both valves in each line must be remote-controlled. In addition:

(1) You must install the choke line above the bottom ram;

(2) You may install the kill line below the bottom ram; and

(3) For a surface BOP system, 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) A fill-up line above the uppermost BOP.

(f) Locking devices installed on the ram-type BOPs.

(g) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated surface pressure.

§ 250.444 What are the choke manifold requirements?

(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 rated working pressure at least as great as the rated working pressure 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 rated working pressure at least as great as the rated working pressure of the ram BOPs.

§ 250.445 What are the requirements for kelly valves, inside BOPs, and drill-string safety valves?

You must use or provide the following BOP equipment during drilling operations:

(a) A kelly valve installed below the swivel (upper kelly valve);

(b) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack;

(c) If you drill with a mud motor and use drill pipe instead of a kelly, you must install one kelly valve above, and one strippable kelly valve below, the joint of drill pipe used in place of a kelly;

(d) On a top-drive system equipped with a remote-controlled valve, you must install a strippable kelly-type valve below the remote-controlled valve;

(e) 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 drill string;

(f) 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 drill string;

(g) When running casing, you must have a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(h) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (*i.e.,* kelly-type valve in a top-drive system) must be essentially full-opening; and

(i) The drilling crew must have ready access to a wrench to fit each manual valve.

§ 250.446 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions properly. The BOP maintenance and inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). You must document the procedures used, record the results of your BOP inspections and maintenance actions, and make available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer;

(b) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system and marine riser at least once every 3 days if weather and sea conditions permit. You may use television cameras to inspect subsea equipment.

§ 250.447 When must I pressure test the BOP system?

You must pressure test your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill-string safety valve):

(a) When installed;

(b) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Manager may require more frequent testing if conditions or BOP performance warrant; and

(c) Before drilling out each string of casing or a liner. The District Manager may allow you to omit this test if you didn't remove the BOP stack to run the casing string or liner and the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your APD which casing strings and liners meet these criteria.

§ 250.448 What are the BOP pressure tests requirements?

When you pressure test the BOP system, you must conduct a low-pressure and a high-pressure test for each BOP component. You must conduct the low-pressure test before the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. Required test pressures are as follows:

(a) *Low-pressure test.* All low-pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.

(b) *High-pressure test for ram-type BOPs, the choke manifold, and other BOP components.* The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated maximum anticipated surface pressure (MASP) 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.

(c) *High pressure test for annular-type BOPs.* The high pressure test must equal 70 percent of the rated working pressure of the equipment or to a pressure approved in your APD.

(d) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

§ 250.449 What additional BOP testing requirements must I meet?

You must meet the following additional BOP testing requirements:

(a) Use water to test a surface BOP system;

(b) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system;

(c) Alternate tests between control stations and pods;

(d) Pressure test the blind or blind-shear ram BOP during stump tests and at all casing points;

(e) The interval between any blind or blind-shear ram BOP pressure tests may not exceed 30 days;

(f) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools;

(g) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(h) Function test annular and ram BOPs every 7 days between pressure tests;

(i) Actuate safety valves assembled with proper casing connections before running casing;

(j) Test all ROV intervention functions on your subsea BOP stack during the stump test. You must also test at least one set of rams during the initial test on the seafloor. You must submit test procedures with your APD or APM for District Manager approval. You must:

(1) ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams and one set of blind-shear rams and unlatching the LMRP; and

(2) document all your test results and make them available to BSEE upon request;

(k) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system during the initial test on the seafloor.

(1) You must submit test procedures with your APD or APM for District Manager approval.

(2) You must document all your test results and make them available to BSEE upon request.

§ 250.450 What are the recordkeeping requirements for BOP tests?

You must record the time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(a) Record BOP test pressures on pressure charts;

(b) Require your onsite representative to sign and date BOP test charts and reports as correct;

(c) Document 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 the control station and pod used during the test;

(e) Identify any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities; and

(f) Retain all records, including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of drilling.

§ 250.451 What must I do in certain situations involving BOP equipment or systems?

The table in this section describes actions that lessees must take when certain situations occur with BOP systems during drilling activities.

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.
(b) Need to repair or replace a surface or subsea BOP system,	First place the well in a safe, controlled condition (*e.g.,* before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck drill pipe,	Record the reason for postponing the test in the driller's report and conduct the required BOP test on the first trip out of the hole.
(d) BOP control station or pod that does not function properly,	Suspend further drilling operations until that station or pod is operable.
(e) Want to drill with a tapered drill-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 drill string.
(f) Install casing rams in a BOP stack,	Test the ram bonnets before running casing.
(g) Want to use an annular BOP with a rated working pressure less than the anticipated surface pressure,	Demonstrate that your well control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Manager.
(h) Use a subsea BOP system in an ice-scour area,	Install the BOP stack in a glory hole. The glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate blind-shear rams or casing shear rams during a well control situation, in which pipe or casing is sheared,	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled.

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;

(j) Before displacing kill-weight drilling fluid from the wellbore, you must obtain prior approval from the District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight drilling 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 that are in place for each flow path,

(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 fluids entering and leaving the wellbore; and

(k) 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.

§ 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 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 100 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.

§ 250.462 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with each drilling crew. Your drill must familiarize the crew with its roles and functions so that all crew members can perform their duties promptly and efficiently.

(a) *Well-control drill plan.* You must prepare a well control drill plan for each well. Your plan must outline the assignments for each crew member and establish times to complete each portion of the drill. You must post a copy of the well control drill plan on the rig floor or bulletin board.

(b) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to drilling operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping.

(c) *Recordkeeping requirements.* For each drill, you must record the following in the driller's report:

(1) The time to be ready to close the diverter or BOP system; and

(2) The total time to complete the entire drill.

(d) *BSEE ordered drill.* A BSEE authorized 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.

§ 250.463 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 form BSEE–0124 with detailed information about the work to the District Manager, unless you have already provided sufficient information in a Well Activity Report, form BSEE–0133 (§ 250.468(b)).

§ 250.466 What records must I keep?

You must keep complete, legible, and accurate records for each well. You must keep drilling records onsite while drilling activities continue. After completion of drilling activities, you must keep all drilling and other well records for the time periods shown in § 250.467. You may keep these records at a location of your choice. The records must contain complete information on all of the following:

(a) Well operations;

(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 in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.

§ 250.467 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,	Ninety days after you complete drilling operations.
(b) Casing and liner pressure tests, diverter tests, and BOP tests,	Two years after the completion of drilling 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 forward the records with a lease assignment.

§ 250.468 What well records am I required to submit?

(a) You must submit 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 to BSEE. Each Region will provide specific instructions for submitting well logs and surveys.

(b) For drilling operations in the GOM OCS Region, you must submit form BSEE–0133, Well Activity Report, to the District Manager on a weekly basis.

(c) For drilling operations in the Pacific or Alaska OCS Regions, you must submit form BSEE–0133, Well Activity Report, to the District Manager on a daily basis.

§ 250.469 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 § 250.466;

(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 prescribes 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.

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 nonrestricted flow of gas. You must locate flare line outlets on the downside

of the facility and as far from the facility as is feasible, taking into account the prevailing wind directions, the wake effects caused by the facility and adjacent structure(s), and the height of all such facilities and structures. You must equip the flare outlet with an automatic ignition system including a pilot-light gas source or an equivalent system. You must have alternate methods for igniting the flare. You must pipe to the flare system used for H_2S all vents from production process equipment, tanks, relief valves, burst plates, and similar devices.

(7) *Corrosion mitigation.* You must use effective means of monitoring and controlling corrosion caused by acid gases (H_2S and CO_2) in both the downhole and surface portions of a production system. You must take specific corrosion monitoring and mitigating measures in areas of unusually severe corrosion where accumulation of water and/or higher concentration of H_2S exists.

(8) *Wireline lubricators.* Lubricators which may be exposed to fluids containing H_2S must be of H_2S-resistant materials.

(9) *Fuel and/or instrument gas.* You must not use gas containing H_2S for instrument gas. You must not use gas containing H_2S for fuel gas without the prior approval of the District 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 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.

§ 250.501 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 Equipment movement.

The movement of well-completion rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the District Manager. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

§ 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 Crew instructions.

Prior to engaging in well-completion operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by BSEE representatives.

§ 250.507 [Reserved]

§ 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) 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

(5) 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.

§ 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.

§ 250.515 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and BOP system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form BSEE–0124 or Form BSEE–0123, as appropriate, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-completion operations 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 string,	At least one set of pipe rams that are capable of sealing around each size of drill string. 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 string. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a subsea BOP stack,	The requirements in § 250.442(a) of this part.

(c) The BOP systems for well completions must be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed.

(3) Locking devices for the pipe-ram preventers.

(4) At least one remote BOP-control station and one BOP-control station on the rig floor.

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided that two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

(d) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string.

(e) The subsea BOP system for well-completions must meet the requirements in § 250.442 of this part.

§ 250.516 Blowout preventer system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed; and

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Manager may require testing every 7 days if conditions or BOP performance warrant.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. The District Manager may approve or require other test pressures or practices. Required test pressures are as follows:

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment.

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) Additional BOP testing requirements. You must:

(1) Use water to test the surface BOP system;

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further completion operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram at least every 30 days;

(5) Function test annulars and rams every 7 days;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools;

(7) Test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(8) Test all ROV intervention functions on your subsea BOP stack during the stump test. You must also test at least one set of rams during the initial test on the seafloor. You must submit test procedures with your APM for District Manager approval. You must:

(i) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams and one set of blind-shear rams and unlatching the LMRP;

(ii) Document all your test results and make them available to BSEE upon request; and

(9) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system during the initial test on the seafloor.

(i) You must submit test procedures with your APM for District Manager approval.

(ii) You must document all your test results and make them available to BSEE upon request.

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible (*i.e.,* first trip out of the hole) after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

(f) *Weekly crew drills.* You must conduct a weekly drill to familiarize all personnel engaged in well-completion operations with appropriate safety measures.

(g) *BOP inspections.* (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). You must document the procedures used, record the results, and make them available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer.

(2) You must visually inspect your BOP system and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect this equipment. The District Manager may approve alternate methods and frequencies to inspect a marine riser.

(h) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). You must document the procedures used, record the results, and make available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer.

(i) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, crew drills, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

(5) Identify any problems or irregularities observed during BOP system and equipment testing and record actions taken to remedy the problems or irregularities;

(6) Retain all records including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of the completion activity; and

(7) After completion of the well, you must retain all the records listed in paragraph (i)(6) of this section 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.

(j) *Alternate methods.* The District Manager may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

§ 250.517 Tubing and wellhead equipment.

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Manager.

(c) 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, (2) subsea wells, (3) hybrid * wells,	the wellhead, the tubing head, the surface wellhead,	all annuli (A, B, C, D, *etc.,* annuli). the production casing annulus (A annulus). 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.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.801 of this part.

Casing Pressure Management

§ 250.518 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 250.530. 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.

§ 250.519 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.

§ 250.520 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.

§ 250.521 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 §§ 250.520 and 250.522.

§ 250.522 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.

§ 250.523 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.

§ 250.524 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 § 250.521;

(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.

§ 250.525 What do I submit if my casing diagnostic test requires action?

Within 14 days after you perform a casing diagnostic test requiring action under § 250.524:

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 § 250.526,	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 § 250.527.	

§ 250.526 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.

§ 250.527 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.

§ 250.528 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.

§ 250.529 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 § 250.522(e).

§ 250.530 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, side-tracked, 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.

Subpart F—Oil and Gas Well-Workover Operations

§ 250.600 General requirements.

Well-workover operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment.

§ 250.601 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.

Workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

§ 250.602 Equipment movement.

The movement of well-workover rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-workover rigs and related equipment unless otherwise approved by the District Manager. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. The well to which a well-workover rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the tree and installing and testing the blowout-preventer (BOP) system. The well from which a well-workover rig or related equipment is to be moved shall also be equipped with a back pressure valve prior to removing the BOP system and installing the tree. Coiled tubing units, snubbing units, or wireline units may be moved onto a platform without shutting in wells.

§ 250.603 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 Crew instructions.

Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by a BSEE representative.

§ 250.607 [Reserved]

§ 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.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

§ 250.611 Traveling-block safety device.

After May 31, 1989, all units being used for well-workover operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.612 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) 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

(4) 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.

§ 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.

§ 250.615 Blowout prevention equipment.

(a) The BOP system, system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form BSEE–0124, requesting approval of the well-workover operation, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-workover operations with the tree removed 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 string,	At least one set of pipe rams that are capable of sealing around each size of drill string. 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 string. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a subsea BOP stack,	The requirements in § 250.442(a) of this part.

(c) The BOP systems for well-workover operations with the tree removed must be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed;

(3) Locking devices for the pipe-ram preventers;

(4) At least one remote BOP-control station and one BOP-control station on the rig floor; and

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

(d) The minimum BOP-system components for well-workover operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string, *i.e.,* small-tubing operations, shall include the following:

(1) Two sets of pipe rams, and

(2) One set of blind rams.

(e) The subsea BOP system for well-workover operations must meet the requirements in § 250.442 of this part.

(f) For coiled tubing operations with the production tree in place, 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
Stripper or annular-type well control component	Stripper or annular-type well control component.	Stripper or annular-type well control component.
Hydraulically-operated blind rams	Hydraulically-operated blind rams	Hydraulically-operated blind rams
Hydraulically-operated shear rams	Hydraulically-operated shear rams	Hydraulically-operated shear rams.
Kill line inlet	Kill line inlet	Kill line inlet.
Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams.
		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 well-workover 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 pre-charge 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.

(g) The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, *i.e.,* snubbing operations, shall include the following:

(1) One set of pipe rams hydraulically operated, and

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool.

(h) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-workover operations when the tree is removed or during well-workover operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

§ 250.616 Blowout preventer system testing, records, and drills.

(a) *BOP pressure tests.* When you pressure test the BOP system you must conduct a low-pressure test and a high-pressure test for each component. You must conduct the low-pressure test before the high-pressure test. For purposes of this section, BOP system components include ram-type BOP's, related control equipment, choke and kill lines, and valves, manifolds, strippers, and safety valves. Surface BOP systems must be pressure tested with water.

(1) *Low pressure tests.* All BOP system components must be successfully tested to a low pressure between 200 and 300 psi. Any initial pressure equal to or greater than 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero before starting the test.

(2) *High pressure tests.* All BOP system components must be successfully tested to the rated working pressure of the BOP equipment, or as otherwise approved by the District Manager. The annular-type BOP must be successfully tested at 70 percent of its rated working pressure or as otherwise approved by the District Manager.

(3) *Other testing requirements.* Variable bore pipe rams must be pressure tested against the largest and smallest sizes of tubulars in use (jointed pipe, seamless pipe) in the well.

(b) Times. The BOP systems shall be tested at the following times:

(1) When installed;

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional, system is operable. The test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams shall be tested at least once every 30 days during operation. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests shall be conducted as soon as possible and before normal operations resume. The reason for postponing testing shall be entered into the operations log.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) *Drills.* All personnel engaged in well-workover operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) *Stump tests.* You may conduct a stump test for the BOP system on location. A plan describing the stump test procedures must be included in your Form BSEE–0124, Application for Permit to Modify, and must be approved by the District Manager.

(e) *Coiled tubing tests.* You must test the coiled tubing connector to a low pressure of 200 to 300 psi, followed by a high pressure test to the rated working pressure of the connector or the expected surface pressure, whichever is less. 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.

(f) *Recordings.* You must record test pressures during BOP and coiled tubing tests on a pressure chart, or with a digital recorder, unless otherwise approved by the District Manager. The test interval for each BOP system component must be 5 minutes, except for coiled tubing operations, which must include a 10 minute high-pressure test for the coiled tubing string. Your representative at the facility must certify that the charts are correct.

(g) *Operations log.* The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers shall be recorded in the operations log. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the operations log. For a subsea system, the pod used during the test shall be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.

(4) Documentation required to be entered in the operation log may instead be referenced in the operations log. All records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections, shall be available for BSEE review at the facility for the duration of well-workover activity. Following completion of the well-workover activity, all such records shall be retained for a period of 2 years at the facility, at the lessee's filed office nearest the OCS facility, or at another location conveniently available to the District Manager.

(h) *Subsea BOPs.* Stump test a subsea BOP system before installation. You must:

(1) Test all ROV intervention functions on your subsea BOP stack during the stump test. You must also test at least one set of rams during the initial test on the seafloor. You must submit test procedures with your APM for District Manager approval. You must:

(i) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams and one set of blind-shear rams and unlatching the LMRP;

(ii) Document all your test results and make them available to BSEE upon request; and

(2) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system during the initial test on the seafloor. You must:

(i) Submit test procedures with your APM for District Manager approval.

(ii) Document the results of each test and make them available to BSEE upon request.

(3) Use water to stump test a subsea BOP system. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system.

§ 250.617 What are my BOP inspection and maintenance requirements?

(a) *BOP inspections.* (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). You must document the procedures used, record the results, and make them available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer.

(2) You must visually inspect your BOP system and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect this equipment. The District Manager may approve alternate methods and frequencies to inspect a marine riser.

(b) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in § 250.198). You must document the procedures used, record the results, and make them available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer.

§ 250.618 Tubing and wellhead equipment.

The lessee shall comply with the following requirements during well-workover operations with the tree removed:

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Manager.

(c) 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, (ii) subsea wells, (iii) hybrid* wells,	the wellhead, the tubing head, the surface wellhead,	all annuli (A, B, C, D, *etc.,* annuli). the production casing annulus (A annulus). 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.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. The tree shall be equipped with a minimum of one master valve and one surface safety valve in the vertical run of the tree when it is reinstalled.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.801 of this part.

§ 250.619 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.

Subpart G [Reserved]

Subpart H—Oil and Gas Production Safety Systems

§ 250.800 General requirements.

(a) Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety and protection of the human, marine, and coastal environments. Production safety systems operated in subfreezing climates shall utilize equipment and procedures selected with consideration of floating ice, icing, and other extreme environmental conditions that may occur in the area. Production shall not commence until the production safety system has been approved and a preproduction inspection has been requested by the lessee.

(b) For all new floating production systems (FPSs) (*e.g.,* column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc.*), you must do all of the following:

(1) Comply with API RP 14J (as incorporated by reference in 30 CFR 250.198);

(2) Meet the drilling and production riser standards of API RP 2RD (as incorporated by reference in 30 CFR 250.198);

(3) Design all stationkeeping systems for floating facilities to meet the standards of API RP 2SK (as incorporated by reference in 30 CFR 250.198), as well as relevant U.S. Coast Guard regulations; and

(4) Design stationkeeping systems for floating facilities to meet structural requirements in subpart I, §§ 250.900 through 250.921 of this part.

§ 250.801 Subsurface safety devices.

(a) *General.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after application and justification, the well is determined by the District Manager to be incapable of natural flowing. These devices may consist of a surface-controlled subsurface safety valve (SSSV), a subsurface-controlled SSSV, an injection valve, a tubing plug, or a tubing/annular subsurface safety device, and any associated safety valve lock or landing nipple.

(b) *Specifications for SSSVs.* Surface-controlled and subsurface-controlled SSSVs and safety valve locks and landing nipples installed in the OCS shall conform to the requirements in § 250.806 of this part.

(c) *Surface-controlled SSSVs.* All tubing installations open to a hydrocarbon-bearing zone which is capable of natural flow shall be equipped with a surface-controlled SSSV, except as specified in paragraphs (d), (f), and (g) of this section. The surface controls may be located on the site or a remote location. Wells not previously equipped with a surface-controlled SSSV and wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV in accordance with paragraph (d)(2) of this section shall be equipped with a surface-controlled SSSV when the tubing is first removed and reinstalled.

(d) *Subsurface-controlled SSSVs.* Wells may be equipped with subsurface-controlled SSSVs in lieu of a surface-controlled SSSV provided the lessee demonstrates to the District Manager's satisfaction that one of the following criteria are met:

(1) Wells not previously equipped with surface-controlled SSSVs shall be so equipped when the tubing is first removed and reinstalled,

(2) The subsurface-controlled SSSV is installed in wells completed from a single-well or multiwell satellite caisson or seafloor completions, or

(3) The subsurface-controlled SSSV is installed in wells with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing.

(e) *Design, installation, and operation of SSSVs.* The SSSVs shall be designed, installed, operated, and maintained to ensure reliable operation.

(1) The device shall be installed at a depth of 100 feet or more below the seafloor within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffins, an alternate setting depth of the subsurface safety device may be approved by the District Manager.

(2) Until a subsurface safety device is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

(3) The well shall not be open to flow while the subsurface safety device is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.

(4) All SSSVs must be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems (as specified in § 250.198).

(f) *Subsurface safety devices in shut-in wells.* (1) New completions (perforated but not placed on production) and completions shut in for a period of 6 months shall be equipped with either—

(i) A pump-through-type tubing plug;

(ii) A surface-controlled SSSV, provided the surface control has been rendered inoperative; or

(iii) An injection valve capable of preventing backflow.

(2) The setting depth of the subsurface safety device shall be approved by the District Manager on a case-by-case basis, when warranted by conditions such as permafrost, unstable bottom conditions, hydrate formations, and paraffins.

(g) *Subsurface safety devices in injection wells.* A surface-controlled SSSV or an injection valve capable of preventing backflow shall be installed in all injection wells. This requirement is not applicable if the District Manager concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually.

(h) *Temporary removal for routine operations.* (1) Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Form BSEE–0124, Application for Permit to Modify, in § 250.601 of this part for a period not to exceed 15 days.

(2) The well shall be identified by a sign on the wellhead stating that the subsurface safety device has been removed. The removal of the subsurface safety device shall be noted in the records as required in § 250.804(b) of this part. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.

(3) A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless

otherwise approved by the District Manager.

(4) The well shall not be allowed to flow while the subsurface safety device is removed, except when flowing the well is necessary for that particular operation. The provisions of this paragraph are not applicable to the testing and inspection procedures in § 250.804 of this part.

(i) *Additional safety equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface safety device is installed after the effective date of this subpart shall be equipped with a landing nipple with flow couplings or other protective equipment above and below to provide for the setting of the SSSV. The control system for all surface-controlled SSSVs shall be an integral part of the platform Emergency Shutdown System (ESD). In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled SSSVs shall close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

(j) *Emergency action.* In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

§ 250.802 Design, installation, and operation of surface production-safety systems.

(a) *General.* All production facilities, including separators, treaters, compressors, headers, and flowlines shall be designed, installed, and maintained in a manner which provides for efficiency, safety of operation, and protection of the environment.

(b) *Platforms.* 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 API RP 14C (as incorporated by reference 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 therein to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are under § 250.1004.

(c) *Specification for surface safety valves (SSV) and underwater safety valves (USV).* All wellhead SSVs, USVs, and their actuators which are installed in the OCS shall conform to the requirements in § 250.806 of this part.

(d) *Use of SSVs and USV's.* All SSVs and USVs must be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (as incorporated by reference in § 250.198). If any SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(e) *Approval of safety-systems design and installation features.* Prior to installation, the lessee shall submit, in duplicate for approval to the District Manager a production safety system application containing information relative to design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or other location conveniently available to the District Manager. All approvals are subject to field verifications. The application shall include the following:

(1) A schematic flow diagram showing tubing pressure, size, capacity, design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, pipeline pumps, metering devices, and other hydrocarbon-handling vessels.

(2) A schematic piping flow diagram (API RP 14C, Figure E, 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 for 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, other than electrical, are to be installed. The area outlined will include the following information:

(A) All major production equipment, wells, and other significant hydrocarbon sources and a description of the type of decking, ceiling, walls (*e.g.,* grating or solid) and firewalls; and

(B) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (*e.g.,* type cable, conduit, or wire).

(ii) Elementary electrical schematic of any platform safety shut-down system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Manager certifying that new installations conform to the approved designs of this subpart.

(6) The design and schematics of the installation and maintenance of all fire- and gas-detection systems shall include the following:

(i) Type, location, and number of detection sensors;

(ii) Type and kind of alarms, including emergency equipment to be activated;

(iii) Method used for detection;

(iv) Method and frequency of calibration; and

(v) A functional block diagram of the detection system, including the electric power supply.

(7) 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.

§ 250.803 Additional production system requirements.

(a) For all production platforms, you must comply with the following production safety system requirements, in addition to the requirements of § 250.802 of this subpart and the requirements of API RP 14C (as incorporated by reference in § 250.198).

(b) *Design, installation, and operation of additional production systems*—(1) Pressure and fired vessels. 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. 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 relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves, except completely redundant relief valves, shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) Steam generators operating at less than 15 pounds per square inch gauge (psig) shall be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. Steam generators operating at greater than 15 psig require, in addition to an LSL, a water-feeding device which will automatically control the water level.

(iii) The lessee shall use pressure recorders to establish the new operating pressure ranges of pressure vessels at any time when there is a change in operating pressures that requires new settings for the high-pressure shut-in sensor and/or the low-pressure shut-in sensor as provided herein. The pressure-recorder charts used to determine current operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Manager. The high-pressure shut-in sensor shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the vessel. This setting shall also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut in before the relief valve activates. The low-pressure shut-in sensor shall activate no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range. The activation of low-pressure sensors on pressure vessels which operate at less than 5 psi shall be approved by the District Manager on a case-by-case basis.

(2) *Flowlines.* (i) You must equip flowlines from wells with high- and low-pressure shut-in sensors located in accordance with section A.1 and Figure A1 of API RP 14C (as incorporated by reference in § 250.198). The lessee shall use pressure recorders to establish the new operating pressure ranges of flowlines at any time when there is a significant change in operating pressures. The most recent pressure-recorder charts used to determine operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Manager. The high-pressure shut-in sensor(s) shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the line. But in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the SSV. The low-pressure shut-in sensor(s) shall be set no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the line in which it is installed.

(ii) If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) shall have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(A) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid hydrocarbons which may be relieved to the vessel.

(B) Two SSV's with independent high-pressure sensors installed with adequate volume upstream of any block valve to allow sufficient time for the valve(s) to close before exceeding the maximum allowable working pressure.

(iii) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(A) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec 17J (as incorporated by reference in § 250.198);

(B) Determine that the unbonded flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way;

(C) Submit to the BSEE District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(D) Submit to the BSEE 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 API Spec 17J (as incorporated by reference in § 250.198).

(3) *Safety sensors.* All shutdown devices, valves, and pressure sensors shall function in a manual reset mode. Sensors with integral automatic reset shall be equipped with an appropriate device to override the automatic reset mode. All pressure sensors shall be equipped to permit testing with an external pressure source.

(4) *ESD.* The ESD must conform to the requirements of Appendix C, section C1, of API RP 14C (as incorporated by reference in § 250.198), and the following:

(i) The manually operated ESD valve(s) shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve.

(ii) Closure of the SSV shall not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV shall close in not more than 2 minutes after the shut-in signal has closed the SSV. Design-delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and be approved by the District Manager.

(iii) A schematic of the ESD which indicates the control functions of all safety devices for the platforms shall be maintained by the lessee on the platform or at the lessee's field office nearest the OCS facility or other location conveniently available to the District Manager.

(5) *Engines:* (i) *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.

(ii) *Diesel engine air intake.* All diesel engine air intakes must be equipped with a device to shutdown 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.

(6) *Glycol dehydration units.* A pressure relief system or an adequate vent shall be installed on the glycol regenerator (reboiler) which will prevent overpressurization. The

discharge of the relief valve shall be vented in a nonhazardous manner.

(7) *Gas compressors.* You must equip compressor installations with the following protective equipment as required in API RP 14C, Sections A4 and A8 (as incorporated by reference in § 250.198).

(i) A Pressure Safety High (PSH), a Pressure Safety Low (PSL), a Pressure Safety Valve (PSV), and a Level Safety High (LSH), and an LSL to protect each interstage and suction scrubber.

(ii) A Temperature Safety High (TSH) on each compressor discharge cylinder.

(iii) The PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designated to actuate automatic shutdown valves (SDV) located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Manager, gas—well gas affected by the closure of the automatic SDV on a compressor suction shall be diverted to the pipeline or shut in at the wellhead.

(iv) A blowdown valve is required on the discharge line of all compressor installations of 1,000 horsepower (746 kilowatts) or greater.

(8) *Firefighting systems.* Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons shall conform to subsection 5.2, Firewater systems, of API RP 14G (as incorporated by reference in § 250.198), Fire Prevention and Control Open Type Offshore Production Platforms, and shall require approval of the District Manager. The following additional requirements shall apply for both open- and closed-production platforms:

(i) A firewater system consisting of rigid pipe with firehose stations or fixed firewater monitors shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed waterspray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during a platform shut-in. If necessary, an alternate fuel or power supply shall be installed to provide for this pump-operating time unless an alternate firefighting system has been approved by the District 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.

(iv) A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the facility or structure.

(v) For operations in subfreezing climates, the lessee shall furnish evidence to the District Manager that the firefighting system is suitable for the conditions.

(9) *Fire- and gas-detection system.* (i) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas. Gas sensors shall be installed in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation which is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit (LEL). One approved method of providing adequate ventilation is a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (*e.g.,* buildings, living quarters, or doghouses) are defined as those areas confined on more than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to all entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500 (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 § 250.198).

(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 which are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(iv) The District 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).

(10) *Electrical equipment.* Electrical equipment and systems shall be designed, installed, and maintained in accordance with the requirements in § 250.114 of this part.

(11) *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. Records by lease, indicating the wells which have erosion-control programs in effect and the results of the programs, shall be maintained by the lessee for a period of 2 years and shall be made available to BSEE upon request.

(c) *General platform operations.* (1) Surface or subsurface safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service shall be flagged.

(2) When wells are disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed, you are not required to comply with the provisions of API RP 14C (as incorporated by reference in § 250.198) or this regulation concerning the following:

(i) Automatic fail-close SSV's on wellhead assemblies, and

(ii) The PSH and PSL shut-in sensors in flowlines from wells.

(3) When pressure or atmospheric vessels are isolated from production facilities (*e.g.,* inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device compliance with API RP 14C or this subpart is not required.

(4) All open-ended lines connected to producing facilities and wells shall be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(d) *Welding and burning practices and procedures.* All welding, burning, and hot-tapping activities shall be conducted according to the specific

requirements in §§ 250.109 through 250.113 of this part.

§ 250.804 Production safety-system testing and records.

(a) *Inspection and testing.* The safety-system devices shall be successfully inspected and tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing must be in accordance with API RP 14C, Appendix D (as incorporated by reference in § 250.198), and the following:

(1) Testing requirements for subsurface safety devices are as follows:

(i) Each surface-controlled subsurface safety device installed in a well, including such devices in shut-in and injection wells, shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, or if a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. Testing shall be in accordance with API RP 14B (as incorporated by reference in § 250.198) to ensure proper operation.

(ii) Each subsurface-controlled SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.

(iii) Each tubing plug installed in a well shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.

(iv) Injection valves shall be tested in the manner as outlined for testing tubing plugs in paragraph (a)(1)(iii) of this section. Leakage rates outlined in paragraph (a)(1)(iii) of this section shall apply.

(2) All PSV's shall be tested for operation at least once every 12 months. These valves shall be either bench-tested or equipped to permit testing with an external pressure source. Weighted disk vent valves used as PSV's on atmospheric tanks may be disassembled and inspected in lieu of function testing.

(3) The following safety devices (excluding electronic pressure transmitters and level sensors) must be tested at least once each calendar month, but at no time will more than 6 weeks elapse between tests:

(i) All PSH and PSL,

(ii) All LSH and LSL controls,

(iii) All automatic inlet SDV's which are actuated by a sensor on a vessel or compressor, and

(iv) All SDV's in liquid discharge lines and actuated by vessel low-level sensors.

(4) The following electronic pressure transmitters and level sensors must be tested at least once every 3 months, but at no time may more than 120 days elapse between tests:

(i) All PSH and PSL, and

(ii) All LSH and LSL controls.

(5) All SSV's and USV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The SSV's and USV's must be tested in accordance with the test procedures specified in API RP 14H (as incorporated by reference in § 250.198). If the SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(6) All flowline Flow Safety Valves (FSV) shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's must be tested for leakage in accordance with the test procedures specified in API RP 14C, Appendix D, section D4, table D2, subsection D (as incorporated by reference in § 250.198). If the leakage measured exceeds a liquid flow of 200 cubic centimeters per minute or a gas flow of 5 cubic feet per minute, the FSV's shall be repaired or replaced.

(7) The TSH shutdown controls installed on compressor installations which can be nondestructively tested shall be tested every 6 months and repaired or replaced as necessary.

(8) All pumps for firewater systems shall be inspected and operated weekly.

(9) All fire- (flame, heat, or smoke) detection systems shall be tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner. Open flame or devices operating at temperatures which could ignite a methane-air mixture shall not be used. All combustible gas-detection systems shall be calibrated every 3 months.

(10) All TSH devices shall be tested at least once every 12 months, excluding those addressed in paragraph (a)(7) of this section and those which would be destroyed by testing. Burner safety low and flow safety low devices shall also be tested at least once every 12 months.

(11) The ESD shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The test shall be conducted by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation.

(12) 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 integrated 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 subsurface and surface safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or other locations conveniently available to the District Manager. These records shall be available for review by a representative of BSEE. The records shall show the present status and history of each device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

§ 250.805 Safety device training.

Personnel installing, inspecting, testing, and maintaining these safety devices and personnel operating the production platforms shall be qualified in accordance with 30 CFR 250, subpart O.

§ 250.806 Safety and pollution prevention equipment quality assurance requirements.

(a) *General requirements.* (1) Except as provided in paragraph (b)(1) of this section, you may install only certified safety and pollution prevention equipment (SPPE) in wells located on the OCS. SPPE includes the following:

(i) Surface safety valves (SSV) and actuators;

(ii) Underwater safety valves (USV) and actuators; and

(iii) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples.

(2) Certified SPPE is equipment the manufacturer certifies as manufactured under a quality assurance program BSEE recognizes. BSEE considers all other SPPE as noncertified. BSEE recognizes two quality assurance programs:

(i) ANSI/ASME SPPE–1–1994 and SPPE–1d–1996 Addenda, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations (as incorporated by reference in § 250.198); and

(ii) API Spec Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry (as incorporated by reference in § 250.198).

(3) All SSV's and USV's must meet the technical specifications of API Spec 6A and 6AV1. All SSSVs must meet the technical specifications of API Specification 14A (as incorporated by reference in § 250.198). However, SSSVs and related equipment planned to be used in high pressure high temperature environments must meet the additional requirements set forth in § 250.807.

(4) For information on all standards mentioned in this section, see § 250.198.

(b) *Use of noncertified SPPE.* (1) Before April 1, 1998, you may continue to use and install noncertified SPPE if it was in your inventory as of April 1, 1988, and was included in a list of noncertified SPPE submitted to BSEE prior to August 29, 1988.

(2) On or after April 1, 1998:

(i) You may not install additional noncertified SPPE; and

(ii) When noncertified SPPE that is already in service requires offsite repair, remanufacturing, or hot work such as welding, you must replace it with certified SPPE.

(c) *Recognizing other quality assurance programs.* The BSEE will consider recognizing other quality assurance programs covering the manufacture of SPPE. If you want BSEE to evaluate other quality assurance programs, submit relevant information about the program and reasons for recognition by BSEE to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; MS–4020; 381 Elden Street, Herndon, Virginia 20170–4817.

§ 250.807 Additional requirements for subsurface safety valves 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), Application for Permit to Modify (APM), or 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 analysis;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing process and procedures used; and

(3) An explanation of why the analysis, process, 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 psig 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 psig 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.

§ 250.808 Hydrogen sulfide.

Production operations in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.490 of this part, shall be conducted in accordance with that section and other relevant requirements of subpart H, Production Safety Systems.

Subpart I—Platforms and Structures

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.

Activity requiring application and approval	Conditions for conducting the activity
(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.

(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),	Fixed and floating platform, as appropriate.
(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;	
(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	

§ 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″ x 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″ x 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.
(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.

Required submittal	Required contents	Other requirements
(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'' sk*etc*hes 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 analysis must indicate a maximum 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.

If . . .	Then . . .
(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.

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, manmade 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;

Type of facility . . .	The CVA must . . .
	(iii) Environmental loading data; (iv) Load determinations; (v) Stress analyses; (vi) Material designations; (vii) Soil and foundation conditions; (viii) Safety factors; and (ix) Other pertinent parameters of the proposed design.
(2) For all floating facilities,	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, or inadequate deck height your platform 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.

§ 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 by April 14, 1999, or the date a pipeline begins service, whichever is later.

(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 by April 14, 1999, the BSEE Regional Supervisor and the Department of Transportation (DOT) Office of Pipeline Safety (OPS) Regional Director may jointly determine the transfer point.

(4) The transfer point serves as a regulatory boundary. An operator may write to the BSEE Regional Supervisor to request an exception to this requirement for an individual facility or area. The Regional Supervisor, in consultation with the OPS Regional Director 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 Office of Pipeline Safety (OPS) Regional Director.

(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 OPS

Regional Director and the BSEE Regional Supervisor.

(ii) The BSEE Regional Supervisor and the OPS Regional Director 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).

§ 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 American Petroleum Institute (API) Spec 6A (as incorporated by reference in § 250.198), 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 B16.5, API Spec 6A, or the equivalent (as incorporated by reference in 30 CFR 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 API Spec 17J, as incorporated by reference in 30 CFR 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.

§ 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, (2) More than 1 year but less than 5 years, (3) 5 or more years,	Isolate the pipeline with a blind flange or a closed block valve at each end of the pipeline. Flush and fill the pipeline with inhibited seawater. 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 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.

§ 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.

(e) Notwithstanding the provisions of paragraph (a) of this section, the requirements to pay filing fees under that paragraph are suspended until January 3, 2006.

§ 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.

(c) Notwithstanding the provisions of paragraph (b) of this section, the requirement to pay a filing fee under that paragraph is suspended until January 3, 2006.

§ 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, Form BOEM–0127, and supporting data as required in § 250.1167, 30 CFR 550.1167, and any additional information required by the BSEE Regional Supervisor.

(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.

§ 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:				
(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	.....	✔	✔	.....

	WPT BSEE–0126 (2 copies)	Gas cap production	Downhole commingling	Production within 500-ft of a unit or lease line
(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)
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 buy-back gas meters or pigging meters; Other applications which request deviations from the approved allocation procedures.

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

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS as incorporated by reference in § 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 § 250.198); and

(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:

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

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

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

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

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

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a total meter factor difference of no greater than 0.0005. The flow rate through the meters during the proving must be within 10 percent of the rate at which the line meter will operate. The final meter factor is determined by averaging the meter factors of the three runs;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(k) *What are the requirements for liquid hydrocarbon allocation meters*? For liquid 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 correction factors and procedures in the API MPMS as incorporated by reference in § 250.198.

§ 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 to ensure accurate and verifiable measurement. You must follow the recommendations in API MPMS (as incorporated by reference 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.

(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.

§ 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 Development and Production Plan, submitted to BOEM or a unitization agreement. A competitive reservoir has one or more producing or producible well completions on each of two or more leases, or portions of leases, with different lease operating interests. For purposes of this paragraph, a producible well completion is a well which is capable of production and which is shut in at the well head or at the surface but not necessarily connected to production facilities and from which the operator plans future production.

(b) You may request that the Regional Supervisor make a preliminary determination whether a reservoir is competitive. When you receive the preliminary determination, you have 30 days (or longer if the Regional Supervisor allows additional time) to concur or to submit an objection with supporting evidence if you do not concur. The Regional Supervisor will make a final determination and notify you and the other lessees.

(c) If you conduct drilling or production operations in a reservoir determined competitive by the Regional Supervisor, you and the other affected lessees must submit for approval a joint plan of operations. You must submit the joint plan within 90 days after the Regional Supervisor makes a final determination that the reservoir is competitive. The joint plan must provide for the development and/or production of the reservoir. You may submit supplemental plans for the Regional Supervisor's approval.

(d) If you and the other affected lessees cannot reach an agreement on a joint Development and Production Plan, submitted to BOEM within the approved period of time, each lessee must submit a separate plan to the Regional Supervisor. The Regional Supervisor will hold a hearing to resolve differences in the separate plans. If the differences in the separate plans are not resolved at the hearing and the Regional Supervisor determines that unitization is necessary under § 250.1301(b), BSEE will initiate unitization under § 250.1304.

§ 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 Index table.

The following table is an index of the sections in this subpart:

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

§ 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 $40,000 per day per violation.

§ 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. The penalty may be up to $500 per 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 violations.

(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 to up to $5,000 per day, beginning with the date of the Notice of Noncompliance, for each violation for as long as you do not correct the violations.

§ 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 §§ 250.1490 through 250.1497, 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).

§ 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 penalties of up to $10,000 per day per violation for each day the violation 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 of up to $25,000 per day for each day each violation 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.

§ 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 §§ 250.1490 through 250.1497, 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).

§ 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.

Bonding Requirements

§ 250.1490 What standards must my BOEM-specified surety instrument meet?

(a) A BOEM-specified surety instrument must be in a form specified in BOEM instructions. BSEE 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.

§ 250.1491 How will BOEM determine the amount of my bond or other surety instrument?

(a) The 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

§ 250.1495 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: Jeffrey Walker, RS/FO, BOEM Alaska OCS Region, 3801 Centerpoint Drive, Suite 500, Anchorage, AK 99503–5823, *jeffrey.walker@boem.gov,* (907) 334–5300.

(2) For Gulf of Mexico and Atlantic OCS: Joshua Joyce, Regional FARM Program Coordinator, BOEM Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard New Orleans, LA 70123–2394, *joshua.joyce@boem.gov,* (504) 736–2779.

(3) For Pacific OCS: Jaron Ming, Lead Leasing Specialist, BOEM Pacific OCS Region, 770 Paseo Camarillo, 2nd Floor, Camarillo, CA 93010, *jaron.ming@boem.gov,* (805) 389–7514.

(b) You must submit an audited consolidated balance sheet annually, and, if requested, additional annual tax returns on the date BSEE first determined that you demonstrated financial solvency as long as you have active appeals, or whenever BSEE 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 BSEE notifies you that you must redemonstrate financial solvency.

§ 250.1496 How will BOEM determine if I am financially solvent?

(a) The 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 §§ 250.1490 and 250.1491 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 §§ 250.1490 and 250.1491 for all orders you have appealed is less than $300 million, you must submit the following to BSEE by one of the methods in § 250.1495(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 250.126. 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 §§ 250.1490 and 250.1491;

(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 §§ 250.1490 and 250.1491;

(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 §§ 250.1490 and 250.1491 or pay the obligation.

§ 250.1497 When will BOEM monitor my financial solvency?

(a) If you are presumptively financially solvent under § 250.1496(b), BOEM will determine your net worth as described under § 250.1496(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 § 250.1496(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 §§ 250.1490 and 250.1491.

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 drilling, well completion, well workover, and well servicing operations. For purposes of this subpart, well completion/well workover means those operations following the drilling of a well that are intended to establish or restore production to a well. It includes small tubing operations but does not include well servicing.

Well servicing means snubbing, coil tubing, and wireline operations.

§ 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 timelapse of at least 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.1610 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 shall be conducted for each drilling crew in accordance with the requirements set forth in § 250.462 of this part or as approved by the District Manager.

§ 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;

(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; and

(f) 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.

§ 250.1704 When must I submit decommissioning applications and reports?

You must submit decommissioning applications and receive approval and submit subsequent reports according to the table in this section.

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,	Include information required under §§ 250.1712 and 250.1721.
	(2) Within 30 days after you plug a well	Include information required under § 250.1717.
	(3) Before you install a subsea protective device	Refer to § 250.1722(a).
	(4) Within 30 days after you complete a protective device trawl test.	Include information required under § 250.1722(d).
	(5) Before you remove any casing stub or mud line suspension equipment and any subsea protective device.	Refer to § 250.1723.
	(6) Within 30 days after you complete site clearance verification activities.	Include information required under § 250.1743(a).

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; that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during abandonment activities; and that the plug meets the requirements in the table in § 250.1715. The Registered Professional Engineer must be registered in a State in the United States. You must submit this certification with your APM (Form BSEE–0124).

§ 250.1713 Must I notify BSEE before I begin well plugging operations?

You must notify the appropriate District Manager at least 48 hours before beginning operations to permanently plug a well.

§ 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 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;

PERMANENT WELL PLUGGING REQUIREMENTS—Continued

If you have . . .	Then you must use . . .
	(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 (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.

(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).

§ 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 800 meters (2,624 feet).

§ 250.1717 After I permanently plug a well, what information must I submit?

Within 30 days after you permanently plug a well, you must submit form BSEE–0124, Application for Permit to Modify (subsequent report), to the appropriate District Manager, and include the following information:

(a) Information included in § 250.1712 with a final well schematic;

(b) Description of the plugging work;

(c) Nature and quantities of material used in the plugs; and

(d) If you cut and pulled any casing string, the following information:

(1) A description of the methods used (including information on explosives, if used);

(2) Size and amount of casing removed; and

(3) Casing removal depth.

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) Within 30 days after you temporarily plug a well, you must submit form BSEE–0124, Application for Permit to Modify (subsequent report), and include the following information:

(1) Information included in § 250.1712 with a well schematic;

(2) Information required by § 250.1717(b), (c), and (d); and

(3) A description of any remaining subsea wellheads, casing stubs, mudline suspension equipment, or other obstructions that extend above the seafloor; and

(h) Submit certification by a Registered Professional Engineer of the well abandonment design and procedures; that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during abandonment activities; and that the plug meets the requirements in the table in § 250.1715. The Registered Professional Engineer must be registered in a State in the United States. You must submit this

certification with your APM (Form BSEE–0124) required by § 250.1712.

§ 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–0124, Application for Permit to Modify 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.

§ 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.
(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) You must comply with the provisions of this subpart and have your SEMS program in effect on or before November 15, 2011, except for the submission of Form BSEE–0131 as required in § 250.1929.

(b) You must submit Form BSEE–0131 on an annual basis beginning March 31, 2011.

(c) If there are any conflicts between the requirements of this subpart and API RP 75 (as incorporated by reference in § 250.198), you must follow the requirements of this subpart.

(d) Nothing in this subpart affects safety or other matters under the jurisdiction of the Coast Guard.

§ 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, inspection, and maintenance of all new and existing facilities, including mobile offshore drilling units (MODU) while under BSEE jurisdiction and Department of 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.

§ 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).

(b) You must also include a job safety analysis (JSA) for OCS activities identified or discussed in your SEMS program (see § 250.1911(b)).

(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).

§ 250.1903 Definitions.

Definitions listed in this section apply to this subpart and supersede definitions in API RP 75, Appendices D and E (as incorporated by reference in § 250.198).

Designated and qualified personnel means employees (not contractors) that are knowledgeable of your program, and have actual work experience and training in implementing and auditing a SEMS or a similar program in an offshore oil and gas environment.

Personnel means direct employee(s) of the operator and contracted workers who are involved with or affected by specific jobs or tasks.

§ 250.1904 Documents incorporated by reference.

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 incorporates all of a document, you are responsible for complying with the provisions of that entire document, except to the extent that section provides otherwise. If any incorporated document uses the word ''should'', it means must for purposes of these regulations.

§§ 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 criteria for hazards analyses must my SEMS program meet?

You must ensure the development and implementation of a hazards analysis (facility level) and a job safety analysis (operations/task level) for all of your facilities. For this subpart, facilities include all types of offshore structures permanently or temporarily attached to the seabed (*i.e.,* mobile offshore drilling units; floating production systems;

floating production, storage and offloading facilities; tension-leg platforms; and spars) used for exploration, development, production, and transportation activities for oil, gas, or sulphur from areas leased in the OCS. Facilities also include DOI regulated pipelines. You must document and maintain current analyses for each operation covered by this section for the life of the operation at the facility. The analyses must be updated when an internal audit is conducted to ensure that it is consistent with the current operations on your facility. Hazards analysis requirements for simple and nearly identical facilities, such as well jackets and single well caissons, may be fulfilled by performing a single hazards analysis which you can apply to all such facilities after you verify that any site specific deviations are addressed in each of the elements of your SEMS program.

(a) Hazards Analysis (facility level). For a hazards analysis (facility level), you must perform an initial hazards analysis on each facility on or before November 15, 2011. The hazards analysis must be appropriate to 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.

(b) Job Safety Analysis (JSA). You must develop and implement a JSA for OCS activities identified or discussed in your SEMS program.

(1) You must keep a copy of the most recent JSA (operations/task level) at the job site and it must be readily accessible to employees.

(2) Your JSA must identify, analyze, and record:

(i) The steps involved in performing a specific job;

(ii) the existing or potential safety and health hazards associated with each step; and

(iii) the recommended action(s)/procedure(s) that will eliminate or reduce these hazards and the risk of a workplace injury or illness.

(3) The supervisor of the person in charge of the task must approve the JSA prior to the commencement of the work.

§ 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 operating, maintenance, and 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 and environmental performance. Operators must ensure that contractors have their own written safe work practices. Contractors may adopt appropriate sections of the operator's SEMS program. Operator and contractor must document their agreement on appropriate contractor safety and environmental policies and practices before the contractor begins work at the operator's facilities.

(a) A contractor is anyone performing work for the lessee. However, these requirements do not apply to contractors providing domestic services to the lessee 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.

§ 250.1915 What criteria for training must be in my SEMS program?

Your SEMS program must establish and implement a training program so that all personnel are trained to work safely and are aware of environmental considerations offshore, in accordance with their duties and responsibilities. Training must address the operating procedures (§ 250.1913), the safe work practices (§ 250.1914), and the emergency response and control measures (§ 250.1918). You must document the qualifications of your instructors. 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 whenever a change is made to operating procedures (§ 250.1913), the safe work practices (§ 250.1914), or the emergency response and control measures (§ 250.1918), personnel will be trained in or otherwise informed of the change before they are expected to operate the facility.

(d) How you will verify that the contractors are trained in the work practices necessary to perform their jobs in a safe and environmentally sound manner, including training on operating procedures (§ 250.1913), the safe work practices (§ 250.1914), or the emergency response and control measures (§ 250.1918).

§ 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) You must have your SEMS program audited by either an independent third-party or your designated and qualified personnel according to the requirements of this subpart and API RP 75, Section 12 (as incorporated by reference in § 250.198) within 2 years of the initial implementation of the SEMS program and at least once every 3 years thereafter. The audit must be a comprehensive audit of all thirteen elements of your SEMS program to evaluate compliance with the requirements of this subpart and API RP 75 to identify areas in which safety and environmental performance needs to be improved.

(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, except your audit interval must not exceed 3 years after the 2 year time period for the first audit.

(6) Section 12.6 Audit Team. The audit that you submit to BSEE must be conducted by either an independent third party or your designated and qualified personnel. The independent third party or your designated and qualified personnel must meet the requirements in § 250.1926.

(c) You must require your auditor (independent third party or your designated and qualified personnel) to submit an audit report of the findings and conclusions of the audit to BSEE within 30 days of the audit completion date. The report must outline the results of the audit, including deficiencies identified.

(d) You must provide the BSEE a copy of your plan for addressing the deficiencies identified in your audit within 30 days of completion of the audit. Your plan must address the following:

(1) A proposed schedule to correct the deficiencies identified in the audit. BSEE will notify you within 14 days of receipt of your plan if your proposed schedule is not acceptable.

(2) The person responsible for correcting each identified deficiency, including their job title.

(e) BSEE may verify that you undertook the corrective actions and that these actions effectively address the audit findings.

§§ 250.1921–250.1923 [Reserved]

§ 250.1924 How will BSEE determine if my SEMS program is effective?

(a) BSEE or its authorized representative may evaluate or visit your facility to determine whether your SEMS program is in place, addresses all required elements, and is effective in protecting the safety and health of workers, the environment, and preventing incidents. BSEE or its authorized representative may evaluate your SEMS program, including documentation of contractors,

independent third parties, your designated and qualified personnel, and audit reports, to assess your SEMS program. These evaluations or visits may be random or based upon the OCS lease operator's or contractor's performance.

(b) For the evaluations, you must make the following available to BSEE upon request:

(1) Your SEMS program;

(2) The qualifications of your independent third-party or your designated and qualified personnel;

(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.

(d) Representatives from BSEE may observe or participate in your SEMS audit. You must notify the BSEE at least 30 days prior to conducting your audit as required in § 250.1920, so that BSEE may make arrangements to observe or participate in the audit.

§ 250.1925 May BSEE direct me to conduct additional audits?

(a) If BSEE identifies safety or non-compliance concerns based on the results of our inspections and evaluations, or as a result of an event, BSEE may direct you to have an independent third-party audit of your SEMS program, in addition to the regular audit required by § 250.1920, or BSEE may conduct an audit.

(1) If BSEE direct you to have an independent third-party audit,

(i) You are responsible for all of the costs associated with the audit, and

(ii) The independent third-party audit must meet the requirements of § 250.1920 of this part and you must ensure that the independent third party submits the findings and conclusions of a BSEE-directed audit according to the requirements in § 250.1920 to BSEE within 30 days after the audit is completed.

(2) If BSEE conducts the audit, BSEE will provide a report of the findings and conclusions within 30 days of the audit.

(b) Findings from these audits may result in enforcement actions as identified in § 250.1927.

(c) You must provide the BSEE a copy of your plan for addressing the deficiencies identified in the BSEE-directed audit within 30 days of completion of the audit as required in § 250.1920.

§ 250.1926 What qualifications must an independent third party or my designated and qualified personnel meet?

(a) You must either choose an independent third-party or your designated and qualified personnel to audit your SEMS program. You must take into account the following qualifications when selecting the third-party or your designated and qualified personnel:

(1) Previous education and experience with SEMS, or similar management related programs.

(2) Technical capabilities of the individual or organization for the specific project.

(3) Ability to perform the independent third-party functions for the specific project considering current commitments.

(4) Previous experience with BSEE regulatory requirements and procedures.

(5) Previous education and experience to comprehend and evaluate how the company's offshore activities, raw materials, production methods and equipment, products, byproducts, and business management systems may impact health and safety performance in the workplace.

(b) You must have procedures to avoid conflicts of interest related to the development of your SEMS program and the independent third party auditor and your designated and qualified personnel.

(c) BSEE may evaluate the qualifications of the independent third parties or your designated and qualified personnel. This may include an audit of documents and procedures or interviews. BSEE may disallow audits by a specific independent third-party or your designated and qualified personnel if they do not meet the criteria of this section.

§ 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 activity must document the results of the JSA in writing and must ensure that records are kept onsite for 30 days. 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) You must keep all records in an orderly manner, readily identifiable, retrievable and legible, and include the date of any and all revisions.

§ 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.

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.

§ 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) [Reserved]

(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 1010–0141 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, subpart D, ''Oil and Gas Drilling Operations.''

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.

§ 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 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 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. Processsing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

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.

§ 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

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Authority: 33 U.S.C. 1321.

Subpart A—General

§ 254.1 Who must submit a spill-response plan?

(a) If you are the owner or operator of an oil handling, storage, or transportation facility, and it is located seaward of the coast line, you must submit a spill-response plan to BSEE for approval. Your spill-response plan must demonstrate that you can respond quickly and effectively whenever oil is discharged from your facility. Refer to § 254.6 for the definitions of ''oil,'' ''facility,'' and ''coast line'' if you have any doubts about whether to submit a plan.

(b) You must maintain a current response plan for an abandoned facility until you physically remove or dismantle the facility or until the Regional Supervisor notifies you in writing that a plan is no longer required.

(c) Owners or operators of offshore pipelines carrying essentially dry gas do not need to submit a plan. You must, however, submit a plan for a pipeline that carries:

(1) Oil;

(2) Condensate that has been injected into the pipeline; or

(3) Gas and naturally occurring condensate.

(d) If you are in doubt as to whether you must submit a plan for an offshore facility or pipeline, you should check with the Regional Supervisor.

(e) If your facility is located landward of the coast line, but you believe your facility is sufficiently similar to OCS facilities that it should be regulated by BSEE, you may contact the Regional Supervisor, 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.

§ 254.2 When must I submit a response plan?

(a) You must submit, and BSEE must approve, a response plan that covers each facility located seaward of the coast line before you may use that facility. To continue operations, you must operate the facility in compliance with the plan.

(b) Despite the provisions of paragraph (a) of this section, you may operate your facility after you submit your plan while BSEE reviews it for approval. To operate a facility without an approved plan, you must certify in writing to the Regional Supervisor that you have the capability to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge. The certification must show that you have ensured by contract, or other means approved by the Regional Supervisor, the availability of private personnel and equipment necessary to respond to the discharge. Verification from the organization(s) providing the personnel and equipment must accompany the certification. BSEE will not allow you to operate a facility for more than 2 years without an approved plan.

(c) If you have a plan that BSEE already approved, you are not required to immediately rewrite the plan to comply with this part. You must, however, submit the information this regulation requires when submitting your first plan revision (see § 254.30) after the effective date of this rule. The Regional Supervisor may extend this deadline upon request.

§ 254.3 May I cover more than one facility in my response plan?

(a) Your response plan may be for a single lease or facility or a group of leases or facilities. All the leases or facilities in your plan must have the same owner or operator (including affiliates) and must be located in the same BSEE Region (see definition of Regional Response Plan in § 254.6).

(b) Regional Response Plans must address all the elements required for a response plan in Subpart B, *Oil Spill Response Plans for Outer Continental Shelf Facilities, or Subpart D, Oil Spill Response Requirements for Facilities Located in State Waters Seaward of the Coast Line,* as appropriate.

(c) When developing a Regional Response Plan, you may group leases or facilities subject to the approval of the Regional Supervisor for the purposes of:

(1) Calculating response times;

(2) Determining quantities of response equipment;

(3) Conducting oil-spill trajectory analyses;

(4) Determining worst case discharge scenarios; and

(5) Identifying areas of special economic and environmental importance that may be impacted and the strategies for their protection.

(d) The Regional Supervisor may specify how to address the elements of a Regional Response Plan. The Regional Supervisor also may require that Regional Response Plans contain additional information if necessary for compliance with appropriate laws and regulations.

§ 254.4 May I reference other documents in my response plan?

You may reference information contained in other readily accessible documents in your response plan. Examples of documents that you may reference are the National Contingency Plan (NCP), Area Contingency Plan (ACP), BSEE or BOEM environmental documents, and Oil Spill Removal Organization (OSRO) documents that are readily accessible to the Regional Supervisor. You must ensure that the Regional Supervisor possesses or is provided with copies of all OSRO documents you reference. You should contact the Regional Supervisor if you want to know whether a reference is acceptable.

§ 254.5 General response plan requirements.

(a) The response plan must provide for response to an oil spill from the facility. You must immediately carry out the provisions of the plan whenever there is a release of oil from the facility. You must also carry out the training, equipment testing, and periodic drills described in the plan, and these measures must be sufficient to ensure the safety of the facility and to mitigate

or prevent a discharge or a substantial threat of a discharge.

(b) The plan must be consistent with the National Contingency Plan and the appropriate Area Contingency Plan(s).

(c) Nothing in this part relieves you from taking all appropriate actions necessary to immediately abate the source of a spill and remove any spills of oil.

(d) In addition to the requirements listed in this part, you must provide any other information the Regional Supervisor requires for compliance with appropriate laws and regulations.

§ 254.6 Definitions.

For the purposes of this part:

Adverse weather conditions mean weather conditions found in the operating area that make it difficult for response equipment and personnel to clean up or remove spilled oil or hazardous substances. These include, but are not limited to: Fog, inhospitable water and air temperatures, wind, sea ice, current, and sea states. It does not refer to conditions such as a hurricane, under which it would be dangerous or impossible to respond to a spill.

Area Contingency Plan means an Area Contingency Plan prepared and published under section 311(j) of the Federal Water Pollution Control Act (FWPCA).

Coast line means the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.

Discharge means any emission (other than natural seepage), intentional or unintentional, and includes, but is not limited to, spilling, leaking, pumping, pouring, emitting, emptying, or dumping.

District 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.

Maximum extent practicable means within the limitations of available technology, as well as the physical limitations of personnel, when responding to a worst case discharge in adverse weather conditions.

National Contingency Plan means the National Oil and Hazardous Substances Pollution Contingency Plan prepared and published under section 311(d) of the FWPCA, (33 U.S.C. 1321(d)) or revised under section 105 of the Comprehensive Environmental Response Compensation and Liability Act (42 U.S.C. 9605).

National Contingency Plan Product Schedule means a schedule of dispersants and other chemical or biological products, maintained by the Environmental Protection Agency, that may be authorized for use on oil discharges in accordance with the procedures found at 40 CFR 300.910.

Oil means oil of any kind or in any form, including but not limited to petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil. This also includes hydrocarbons produced at the wellhead in liquid form (includes distillates or condensate associated with produced natural gas), and condensate that has been separated from a gas prior to injection into a pipeline. It does not include petroleum, including crude oil or any fraction thereof, which is specifically listed or designated as a hazardous substance under paragraphs (A) through (F) of section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. 9601) and which is subject to the provisions of that Act. It also does not include animal fats and oils and greases and fish and marine mammal oils, within the meaning of paragraph (2) of section 61(a) of title 13, United States Code, and oils of vegetable origin, including oils from the seeds, nuts, and kernels referred to in paragraph (1)(A) of that section.

Oil spill removal organization (OSRO) means an entity contracted by an owner or operator to provide spill-response equipment and/or manpower in the event of an oil or hazardous substance spill.

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

Owner or *operator* means, in the case of an offshore facility, any person owning or operating such offshore facility. In the case of any abandoned offshore facility, it means the person who owned such facility immediately prior to such abandonment.

Pipeline means pipe and any associated equipment, appurtenance, or building used or intended for use in the transportation of oil located seaward of the coast line, except those used for deep-water ports. Pipelines do not include vessels such as barges or shuttle tankers used to transport oil from facilities located seaward of the coast line.

Qualified individual means an English-speaking representative of an owner or operator, located in the United States, available on a 24-hour basis, with full authority to obligate funds, carry out removal actions, and communicate with the appropriate Federal officials and the persons providing personnel and equipment in removal operations.

Regional Response Plan means a spill-response plan required by this part which covers multiple facilities or leases of an owner or operator, including affiliates, which are located in the same 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 a response plan who staff the organizational structure to manage spill response.

Spill-response coordinator means a trained person charged with the responsibility and designated the commensurate authority for directing and coordinating response operations.

Spill-response operating team means the trained persons who respond to spills through deployment and operation of oil-spill response equipment.

State waters located seaward of the coast line means the belt of the seas measured from the coast line and extending seaward a distance of 3 miles (except the coast of Texas and the Gulf coast of Florida, where the State waters extend seaward a distance of 3 leagues).

You means the owner or the operator as defined in this section.

§ 254.7 How do I submit my response plan to the BSEE?

You must submit the number of copies of your response plan 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 Regional Supervisor for further guidance.

(a) Send plans for facilities located seaward of the coast line of Alaska to: Bureau of Safety and Environmental Enforcement, Regional Supervisor, Field Operations, Alaska OCS Region, 3801 Centerpoint Drive, Suite #500, Anchorage, AK 99503–5823.

(b) Send plans for facilities in the Gulf of Mexico or Atlantic Ocean to: Bureau of Safety and Environmental Enforcement, Regional Supervisor, Field Operations, Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, LA 70123–2394.

(c) Send plans for facilities in the Pacific Ocean (except seaward of the coast line of Alaska) to: Bureau of Safety and Environmental Enforcement, Regional Supervisor, Office of Development Operations and Safety, Pacific OCS Region, 770 Paseo Camarillo, Camarillo, CA 93010–6064.

§ 254.8 May I appeal decisions under this 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 1010–0091. The title of this information collection is ''30 CFR part 254, Oil Spill Response Requirements for Facilities Located Seaward of the Coast line.''

(b) 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, 381 Elden Street, Herndon, VA 20170.

Subpart B—Oil-Spill Response Plans for Outer Continental Shelf Facilities

§ 254.20 Purpose.

This subpart describes the requirements for preparing spill-response plans for facilities located on the OCS.

§ 254.21 How must I format my response plan?

(a) You must divide your response plan for OCS facilities into the sections specified in paragraph (b) of this section and explained in the other sections of this subpart. The plan must have an easily found marker identifying each section. You may use an alternate format if you include a cross-reference table to identify the location of required sections. You may use alternate contents if you can demonstrate to the Regional Supervisor that they provide for equal or greater levels of preparedness.

(b) Your plan must include:

(1) Introduction and plan contents.

(2) Emergency response action plan.

(3) Appendices:

(i) Equipment inventory.

(ii) Contractual agreements.

(iii) Worst case discharge scenario.

(iv) Dispersant use plan.

(v) In situ burning plan.

(vi) Training and drills.

§ 254.22 What information must I include in the ''Introduction and plan contents'' section?

The ''Introduction and plan contents'' section must provide:

(a) Identification of the facility the plan covers, including its location and type;

(b) A table of contents;

(c) A record of changes made to the plan; and

(d) A cross-reference table, if needed, because you are using an alternate format for your plan.

§ 254.23 What information must I include in the ''Emergency response action plan'' section?

The ''Emergency response action plan'' section is the core of the response plan. Put information in easy-to-use formats such as flow charts or tables where appropriate. This section must include:

(a) Designation, by name or position, of a trained qualified individual (QI) who has full authority to implement removal actions and ensure immediate notification of appropriate Federal officials and response personnel.

(b) Designation, by name or position, of a trained spill management team available on a 24-hour basis. The team must include a trained spill-response coordinator and alternate(s) who have the responsibility and authority to direct and coordinate response operations on your behalf. You must describe the team's organizational structure as well as the responsibilities and authorities of each position on the spill management team.

(c) Description of a spill-response operating team. Team members must be trained and available on a 24-hour basis to deploy and operate spill-response equipment. They must be able to respond within a reasonable minimum specified time. You must include the number and types of personnel available from each identified labor source.

(d) A planned location for a spill-response operations center and provisions for primary and alternate communications systems available for use in coordinating and directing spill-response operations. You must provide telephone numbers for the response operations center. You also must provide any facsimile numbers and primary and secondary radio frequencies that will be used.

(e) A listing of the types and characteristics of the oil handled, stored, or transported at the facility.

(f) Procedures for the early detection of a spill.

(g) Identification of procedures you will follow in the event of a spill or a substantial threat of a spill. The procedures should show appropriate response levels for differing spill sizes including those resulting from a fire or explosion. These will include, as appropriate:

(1) Your procedures for spill notification. The plan must provide for the use of the oil spill reporting forms included in the Area Contingency Plan or an equivalent reporting form.

(i) Your procedures must include a current list which identifies the following by name or position, corporate address, and telephone number (including facsimile number if applicable):

(A) The qualified individual;

(B) The spill-response coordinator and alternate(s); and

(C) Other spill-response management team members.

(ii) You must also provide names, telephone numbers, and addresses for the following:

(A) OSRO's that the plan cites;

(B) Federal, State, and local regulatory agencies that you must consult to obtain site specific environmental information; and

(C) Federal, State, and local regulatory agencies that you must notify when an oil spill occurs.

(2) Your methods to monitor and predict spill movement;

(3) Your methods to identify and prioritize the beaches, waterfowl, other marine and shoreline resources, and areas of special economic and environmental importance;

(4) Your methods to protect beaches, waterfowl, other marine and shoreline resources, and areas of special economic or environmental importance;

(5) Your methods to ensure that containment and recovery equipment as well as the response personnel are mobilized and deployed at the spill site;

(6) Your methods to ensure that devices for the storage of recovered oil are sufficient to allow containment and recovery operations to continue without interruption;

(7) Your procedures to remove oil and oiled debris from shallow waters and along shorelines and rehabilitating waterfowl which become oiled;

(8) Your procedures to store, transfer, and dispose of recovered oil and oil-contaminated materials and to ensure that all disposal is in accordance with Federal, State, and local requirements; and

(9) Your methods to implement your dispersant use plan and your in situ burning plan.

§ 254.24 What information must I include in the ''Equipment inventory'' appendix?

Your ''Equipment inventory appendix'' must include:

(a) An inventory of spill-response materials and supplies, services, equipment, and response vessels available locally and regionally. You must identify each supplier and provide their locations and telephone numbers.

(b) A description of the procedures for inspecting and maintaining spill-response equipment in accordance with § 254.43.

§ 254.25 What information must I include in the ''Contractual agreements'' appendix?

Your ''Contractual agreements'' appendix must furnish proof of any contracts or membership agreements with OSRO's, cooperatives, spill-response service providers, or spill management team members who are not your employees that you cite in the plan. To provide this proof, submit copies of the contracts or membership agreements or certify that contracts or membership agreements are in effect. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour-per-day basis.

§ 254.26 What information must I include in the ''Worst case discharge scenario'' appendix?

The discussion of your worst case discharge scenario must include all of the following elements:

(a) The volume of your worst case discharge scenario determined using the criteria in § 254.47. Provide any assumptions made and the supporting calculations used to determine this volume.

(b) An appropriate trajectory analysis specific to the area in which the facility is located. The analysis must identify onshore and offshore areas that a discharge potentially could affect. The trajectory analysis chosen must reflect the maximum distance from the facility that oil could move in a time period that it reasonably could be expected to persist in the environment.

(c) A list of the resources of special economic or environmental importance that potentially could be impacted in the areas identified by your trajectory analysis. You also must state the strategies that you will use for their protection. At a minimum, this list must include those resources of special economic and environmental importance, if any, specified in the appropriate Area Contingency Plan(s).

(d) A discussion of your response to your worst case discharge scenario in adverse weather conditions. This discussion must include:

(1) A description of the response equipment that you will use to contain and recover the discharge to the maximum extent practicable. This description must include the types, location(s) and owner, quantity, and capabilities of the equipment. You also must include the effective daily recovery capacities, where applicable. You must calculate the effective daily recovery capacities using the methods described in § 254.44. For operations at a drilling or production facility, your scenario must show how you will cope with the initial spill volume upon arrival at the scene and then support operations for a blowout lasting 30 days.

(2) A description of the personnel, materials, and support vessels that would be necessary to ensure that the identified response equipment is deployed and operated promptly and effectively. Your description must include the location and owner of these resources as well as the quantities and types (if applicable);

(3) A description of your oil storage, transfer, and disposal equipment. Your description must include the types, location and owner, quantity, and capacities of the equipment; and

(4) An estimation of the individual times needed for:

(i) Procurement of the identified containment, recovery, and storage equipment;

(ii) Procurement of equipment transportation vessel(s);

(iii) Procurement of personnel to load and operate the equipment;

(iv) Equipment loadout (transfer of equipment to transportation vessel(s));

(v) Travel to the deployment site (including any time required for travel from an equipment storage area); and

(vi) Equipment deployment.

(e) In preparing the discussion required by paragraph (d) of this section, you must:

(1) Ensure that the response equipment, materials, support vessels, and strategies listed are suitable, within the limits of current technology, for the range of environmental conditions anticipated at your facility; and

(2) Use standardized, defined terms to describe the range of environmental conditions anticipated and the capabilities of response equipment. Examples of acceptable terms include those defined in American Society for Testing of Materials (ASTM) publication F625–94, *Standard Practice for Describing Environmental Conditions Relevant to Spill Control Systems for Use on Water,* and ASTM F818–93, *Standard Definitions Relating to Spill Response Barriers.*

§ 254.27 What information must I include in the ''Dispersant use plan'' appendix?

Your dispersant use plan must be consistent with the National Contingency Plan Product Schedule and other provisions of the National Contingency Plan and the appropriate Area Contingency Plan(s). The plan must include:

(a) An inventory and a location of the dispersants and other chemical or biological products which you might use on the oils handled, stored, or transported at the facility;

(b) A summary of toxicity data for these products;

(c) A description and a location of any application equipment required as well as an estimate of the time to commence application after approval is obtained;

(d) A discussion of the application procedures;

(e) A discussion of the conditions under which product use may be requested; and

(f) An outline of the procedures you must follow in obtaining approval for product use.

§ 254.28 What information must I include in the ''In situ burning plan'' appendix?

Your in situ burning plan must be consistent with any guidelines authorized by the National Contingency Plan and the appropriate Area Contingency Plan(s). Your in situ burning plan must include:

(a) A description of the in situ burn equipment including its availability, location, and owner;

(b) A discussion of your in situ burning procedures, including provisions for ignition of an oil spill;

(c) A discussion of environmental effects of an in situ burn;

(d) Your guidelines for well control and safety of personnel and property;

(e) A discussion of the circumstances in which in situ burning may be appropriate;

(f) Your guidelines for making the decision to ignite; and

(g) An outline of the procedures you must follow to obtain approval for an in situ burn.

§ 254.29 What information must I include in the ''Training and drills'' appendix?

Your ''Training and drills'' appendix must:

(a) Identify and include the dates of the training provided to members of the spill-response management team and the qualified individual. The types of training given to the members of the spill-response operating team also must be described. The training requirements for your spill management team and your spill-response operating team are specified in § 254.41. You must designate a location where you keep course completion certificates or attendance records for this training.

(b) Describe in detail your plans for satisfying the exercise requirements of § 254.42. You must designate a location where you keep the records of these exercises.

§ 254.30 When must I revise my response plan?

(a) You must review your response plan at least every 2 years and submit all resulting modifications to the Regional Supervisor. If this review does not result in modifications, you must inform the Regional Supervisor in writing that there are no changes.

(b) You must submit revisions to your plan for approval within 15 days whenever:

(1) A change occurs which significantly reduces your response capabilities;

(2) A significant change occurs in the worst case discharge scenario or in the type of oil being handled, stored, or transported at the facility;

(3) There is a change in the name(s) or capabilities of the oil spill removal organizations cited in the plan; or

(4) There is a significant change to the Area Contingency Plan(s).

(c) The Regional Supervisor may require that you resubmit your plan if the plan has become outdated or if numerous revisions have made its use difficult.

(d) The Regional Supervisor will periodically review the equipment inventories of OSRO's to ensure that sufficient spill removal equipment is available to meet the cumulative needs of the owners and operators who cite these organizations in their plans.

(e) The Regional Supervisor may require you to revise your plan if significant inadequacies are indicated by:

(1) Periodic reviews (described in paragraph (d) of this section);

(2) Information obtained during drills or actual spill responses; or

(3) Other relevant information the Regional Supervisor obtained.

Subpart C—Related Requirements for Outer Continental Shelf Facilities

§ 254.40 Records.

You must make all records of services, personnel, and equipment provided by OSRO's or cooperatives available to any authorized 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 response plan for at least 2 years. They must be made available to any authorized BSEE representative upon request.

§ 254.42 Exercises for your response personnel and equipment.

(a) You must exercise your entire response plan at least once every 3 years (triennial exercise). You may satisfy this requirement by conducting separate exercises for individual parts of the plan over the 3-year period; you do not have to exercise your entire response plan at one time.

(b) In satisfying the triennial exercise requirement, you must, at a minimum, conduct:

(1) An annual spill management team tabletop exercise. The exercise must test the spill management team's organization, communication, and decision making in managing a response. You must not reveal the spill scenario to team members before the exercise starts.

(2) An annual deployment exercise of response equipment identified in your plan that is staged at onshore locations. You must deploy and operate each type of equipment in each triennial period. However, it is not necessary to deploy and operate each individual piece of equipment.

(3) An annual notification exercise for each facility that is manned on a 24-hour basis. The exercise must test the ability of facility personnel to communicate pertinent information in a timely manner to the qualified individual.

(4) A semiannual deployment exercise of any response equipment which the 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 plan. Records showing that OSRO's and oil spill removal cooperatives have deployed each type of equipment also must be maintained for the 3-year cycle.

(f) You must inform the Regional Supervisor of the date of any exercise required by paragraph (b)(1), (2), or (4) of this section at least 30 days before the exercise. This will allow 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 Regional Supervisor may require changes in the frequency or location of the required exercises, equipment to be deployed and operated, or deployment procedures or strategies. The Regional Supervisor may evaluate the results of the exercises and advise the owner or operator of any needed changes in response equipment, procedures, or strategies.

(i) Compliance with the National Preparedness for Response Exercise Program (PREP) Guidelines will satisfy the exercise requirements of this section. Copies of the PREP document may be obtained from the Regional Supervisor.

§ 254.43 Maintenance and periodic inspection of response equipment.

(a) You must ensure that the response equipment listed in your response plan is inspected at least monthly and is maintained, as necessary, to ensure optimal performance.

(b) You must ensure that records of the inspections and the maintenance activities are kept for at least 2 years and are made available to any authorized BSEE representative upon request.

§ 254.44 Calculating response equipment effective daily recovery capacities.

(a) You are required by § 254.26(d)(1) to calculate the effective daily recovery capacity of the response equipment identified in your response plan that you would use to contain and recover your worst case discharge. You must calculate the effective daily recovery capacity of the equipment by multiplying the manufacturer's rated throughput capacity over a 24-hour period by 20 percent. This 20 percent efficiency factor takes into account the limitations of the recovery operations due to available daylight, sea state, temperature, viscosity, and emulsification of the oil being recovered. You must use this calculated rate to determine if you have sufficient recovery capacity to respond to your worst case discharge scenario.

(b) If you want to use a different efficiency factor for specific oil recovery devices, you must submit evidence to substantiate that efficiency factor. Adequate evidence includes verified performance data measured during actual spills or test data gathered according to the provisions of § 254.45(b) and (c).

§ 254.45 Verifying the capabilities of your response equipment.

(a) The Regional Supervisor may require performance testing of any spill-response equipment listed in your response plan to verify its capabilities if the equipment:

(1) Has been modified;

(2) Has been damaged and repaired; or

(3) Has a claimed effective daily recovery capacity that is inconsistent with data otherwise available to 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.

§ 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 Regional Supervisor must receive this confirmation within 15 days after the spillage has been stopped. All reports must include the cause, location, volume, and remedial action taken. Reports of spills of more than 50 barrels must include information on the sea state, meteorological conditions, and the size and appearance of the slick. The Regional Supervisor may require additional information if it is determined that an analysis of the response is necessary.

(c) If you observe a spill resulting from operations at another offshore facility, you must immediately notify the responsible party and the Regional Supervisor.

§ 254.47 Determining the volume of oil of your worst case discharge scenario.

You must calculate the volume of oil of your worst case discharge scenario as follows:

(a) For an oil production platform facility, the size of your worst case discharge scenario is the sum of the following:

(1) The maximum capacity of all oil storage tanks and flow lines on the facility. Flow line volume may be estimated; and

(2) The volume of oil calculated to leak from a break in any pipelines connected to the facility considering shutdown time, the effect of hydrostatic pressure, gravity, frictional wall forces and other factors; and

(3) The daily production volume from an uncontrolled blowout of the highest capacity well associated with the facility. In determining the daily discharge rate, you must consider reservoir characteristics, casing/production tubing sizes, and historical production and reservoir pressure data. Your scenario must discuss how to respond to this well flowing for 30 days as required by § 254.26(d)(1).

(b) For exploratory or development drilling operations, the size of your worst case discharge scenario is the daily volume possible from an uncontrolled blowout. In determining the daily discharge rate, you must consider any known reservoir characteristics. If reservoir characteristics are unknown, you must

consider the characteristics of any analog reservoirs from the area and give an explanation for the selection of the reservoir(s) used. Your scenario must discuss how to respond to this well flowing for 30 days as required by § 254.26(d)(1).

(c) For a pipeline facility, the size of your worst case discharge scenario is the volume possible from a pipeline break. You must calculate this volume as follows:

(1) Add the pipeline system leak detection time to the shutdown response time.

(2) Multiply the time calculated in paragraph (c)(1) of this section by the highest measured oil flow rate over the preceding 12-month period. For new pipelines, you should use the predicted oil flow rate in the calculation.

(3) Add to the volume calculated in paragraph (c)(2) of this section the total volume of oil that would leak from the pipeline after it is shut in. Calculate this volume by taking into account the effects of hydrostatic pressure, gravity, frictional wall forces, length of pipeline segment, tie-ins with other pipelines, and other factors.

(d) If your facility which stores, handles, transfers, processes, or transports oil does not fall into the categories listed in paragraph (a), (b), or (c) of this section, contact the Regional Supervisor for instructions on the calculation of the volume of your worst case discharge scenario.

Subpart D—Oil-Spill Response Requirements for Facilities Located in State Waters Seaward of the Coast Line

§ 254.50 Spill response plans for facilities located in State waters seaward of the coast line.

Owners or operators of facilities located in State waters seaward of the coast line must submit a spill-response plan to 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 response plan.

You may modify an existing response plan covering a lease or facility on the OCS to include a lease or facility in State waters located seaward of the coast line. Since this plan would cover more than one lease or facility, it would be considered a Regional Response Plan. You should refer to § 254.3 and contact the appropriate regional BSEE office if you have any questions on how to prepare this Regional Response Plan.

§ 254.52 Following the format for an OCS response plan.

You may develop a response plan following the requirements for plans for OCS facilities found in subpart B of this part.

§ 254.53 Submitting a response plan developed under State requirements.

(a) You may submit a response plan to BSEE for approval that you developed in accordance with the laws or regulations of the appropriate State. The plan must contain all the elements the State and OPA require and must:

(1) Be consistent with the requirements of the National Contingency Plan and appropriate Area Contingency Plan(s).

(2) Identify a qualified individual and require immediate communication between that person and appropriate Federal officials and response personnel if there is a spill.

(3) Identify any private personnel and equipment necessary to remove, to the maximum extent practicable, a worst case discharge as defined in § 254.47. The plan must provide proof of contractual services or other evidence of a contractual agreement with any OSRO's or spill management team members who are not employees of the owner or operator.

(4) Describe the training, equipment testing, periodic unannounced drills, and response actions of personnel at the facility. These must ensure both the safety of the facility and the mitigation or prevention of a discharge or the substantial threat of a discharge.

(5) Describe the procedures you will use to periodically update and resubmit the plan for approval of each significant change.

(b) Your plan developed under State requirements also must include the following information:

(1) A list of the facilities and leases the plan covers and a map showing their location;

(2) A list of the types of oil handled, stored, or transported at the facility;

(3) Name and address of the State agency to whom the plan was submitted;

(4) Date you submitted the plan to the State;

(5) If the plan received formal approval, the name of the approving organization, the date of approval, and a copy of the State agency's approval letter if one was issued; and

(6) Identification of any regulations or standards used in preparing the plan.

§ 254.54 Spill prevention for facilities located in State waters seaward of the coast line.

In addition to your response plan, you must submit to the Regional Supervisor a description of the steps you are taking to prevent spills of oil or mitigate a substantial threat of such a discharge. You must identify all State or Federal safety or pollution prevention requirements that apply to the prevention of oil spills from your facility, and demonstrate your compliance with these requirements. You also should include a description of industry safety and pollution prevention standards your facility meets. The Regional Supervisor may prescribe additional equipment or procedures for spill prevention if it is determined that your efforts to prevent spills do not reflect good industry practices.

PART 256—LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

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256.70 Extension of lease by drilling or well reworking operations.
256.71 Directional drilling.
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256.79 Effect of regulations on lease.
256.80 [Reserved]

Subpart M—Studies [Reserved]

Subpart N—Bonus or Royalty Credits for Exchange of Certain Leases Offshore Florida [Reserved]

Authority: 31 U.S.C. 9701, 42 U.S.C. 6213, 43 U.S.C. 1334, Pub. L. 109–432.

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

§ 256.0 [Reserved]

§ 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.

§§ 256.2–256.5 [Reserved]

§ 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.

§§ 256.8–256.12 [Reserved]

Subpart B—Oil and Gas Leasing Program [Reserved]

Subpart C—Reports From Federal Agencies [Reserved]

Subpart D—Call for Information and Nominations [Reserved]

Subpart E—Area and Identification and Tract Size [Reserved]

Subpart F—Lease Sales [Reserved]

Subpart H—Rentals and Royalties [Reserved]

Subpart I—Bonding [Reserved]

Subpart J—Assignments, Transfers, and Extensions

§§ 256.62–256.68 [Reserved]

§ 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 K—Termination of Leases

§ 256.76 [Reserved]

§ 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 L—Section 6 Leases

§ 256.79 Effect of regulations on lease.

(a) All regulations in this part, insofar as they are applicable, shall supersede the provisions of any lease which is maintained under section 6(a) of the Act. However, the provisions of a lease relating to area, minerals, rentals, royalties (subject to sections 6(a) (8) and (9) of the Act), and term (subject to section 6(a)(10) of the Act and, as to sulfur, subject to section 6(b)(2) of the Act) shall continue in effect, and, in the event of any conflict or inconsistency, shall take precedence over these regulations.

(b) A lease maintained under section 6(a) of the Act shall also be subject to all operating and conservation regulations applicable to the OCS. In addition, the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way are applicable, to the extent that those regulations are not contrary to or inconsistent with the lease provisions relating to area, the minerals, rentals, royalties and term. The lessee shall comply with any provision of the lease as validated, the subject matter of which is not covered in the regulations in this part.

§ 256.80 [Reserved]

Subpart M—Studies [Reserved]

Subpart N—Bonus or Royalty Credits for Exchange of Certain Leases Offshore Florida [Reserved]

PART 259—[RESERVED]

PART 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.

§ 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

Subpart A—[Reserved]

Subpart B—[Reserved]

Subpart C—Obligations Under This Part

Interrupted Activities

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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?
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280.28 May I relinquish my permit?

Subpart D—[Reserved]

Subpart E—[Reserved]

Authority: 43 U.S.C. 1334.

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 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.

§ 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 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.

Subpart D—[Reserved]

Subpart E—[Reserved]

PART 281—[RESERVED]

PART 282—OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR

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Subpart E—Appeals

282.50 Appeals.

Authority: 43 U.S.C. 1334.

Subpart A—General

§ 282.0 Authority for information collection.

The information collection requirements in this part have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1010–0081. The information is being collected to inform the 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.

§ 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.

§ 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 for approval in accordance with the requirements for the approval of such plans in this part.

(e)(1) When the Director orders or issues a suspension or a temporary prohibition pursuant to paragraph (b)(2) of this section, the Director may require the lessee to conduct site-specific studies to identify and evaluate the cause(s) of the hazard(s) generating the suspension or temporary prohibition, the potential for damage from the hazard(s), and the measures available for mitigating the hazard(s). The nature, scope, and content of any study shall be subject to approval by the Director. The lessee shall furnish copies and all results of any such study to the Director. The cost of the study shall be borne by the lessee unless the Director arranges for the cost of the study to be borne by a party other than the lessee. The Director shall make results of any such study available to interested parties and to the public as soon as practicable after the completion of the study and submission of the results thereof.

(2) When the Director determines that measures are necessary, on the basis of the results of the studies conducted in accordance with paragraph (e)(1) of this section and other information available to and identified by the Director, the lessee shall be required to take appropriate measures to mitigate, avoid, or minimize the damage or potential damage on which the suspension or temporary prohibition is based. When deemed appropriate by the Director, the lessee shall submit a revised Delineation, Testing, or Mining Plan to incorporate the mitigation measures required by the Director. In choosing between alternative mitigation measures, the Director shall balance the cost of the required measures against the reduction or potential reduction in damage or threat of damage or harm to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the National security or defense, or to the marine, coastal, or human environment.

(f)(1) If under the provisions of paragraphs (b)(2), (3), and (4) of this section, the Director, with respect to any lease, directs the suspension of production or other operations on the entire leasehold, no payment of rental or minimum royalty shall be due for or during the period of the directed suspension and the time for the lessee specify royalty free period of a period of reduced royalty pursuant to 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.

§ 282.14 Noncompliance, remedies, and penalties.

(a)(1) If the Director determines that a lessee has failed to comply with applicable provisions of law; the regulations in this part; other applicable regulations; the lease; the approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and the Director determines that such noncompliance poses a threat of immediate, serious, or irreparable damage to the environment, the mine or the deposit being mined, or other valuable mineral deposits or other resources, the Director shall order the lessee to take immediate and appropriate remedial action to alleviate the threat. Any oral orders shall be followed up by service of a notice of noncompliance upon the lessee by delivery in person to the lessee or agent, or by certified or registered mail addressed to the lessee at the last known address.

(2) If the Director determines that the lessee has failed to comply with applicable provisions of law; the regulations in this part; other applicable regulations; the lease; the requirements of an approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and such noncompliance does not pose a threat of immediate, serious, or irreparable damage to the environment, the mine or the deposit being mined, or other valuable mineral deposits or other resources, the Director shall serve a notice of noncompliance upon the lessee by delivery in person to the lessee or agent or by certified or registered mail addressed to the lessee at the last known address.

(b) A notice of noncompliance shall specify in what respect(s) the lessee has failed to comply with the provisions of applicable law; regulations; the lease; the requirements of an approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and shall specify the action(s) which must be taken to correct the noncompliance and the time limits within which such action must be taken.

(c) Failure of a lessee to take the actions specified in the notice of noncompliance within the time limit specified shall be grounds for a suspension of operations and other appropriate actions, including but not limited to the assessment of a civil penalty of up to $10,000 per day for each violation that is not corrected within the time period specified (43 U.S.C. 1350(b)).

(d) Whenever the Director determines that a violation of or failure to comply with any provision of the Act; or any provision of a lease, license, or permit issued pursuant to the Act; or any provision of any regulation promulgated under the Act probably occurred and that such apparent violation continued beyond notice of the violation and the expiration of the reasonable time period allowed for corrective action, the Director shall follow the procedures concerning remedies and penalties in subpart N, Remedies and Penalties, of 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)).

§ 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, the lessee will be reimbursed by the United States for the actual costs which it incurs as a result of its providing food, quarters, and transportation for a BSEE representative's stay of more than 10 hours. Request for reimbursement must be submitted within 60 days following the cost being incurred.

(e) Mining and processing vessels, platforms, structures, artificial islands, and mobile drilling units which have helicopter landing facilities shall be identified with at least one sign using letters and figures not less than 12 inches in height. Signs for structures without helicopter landing facilities shall be identified with at least one sign using letters and figures not less than 3 inches in height. Signs shall be affixed at a location that is visible to

approaching traffic and shall contain the following information which may be abbreviated:

(1) Name of the lease operator;

(2) The area designation based on Official OCS Protraction Diagrams;

(3) The block number in which the facility is located; and

(4) Vessel, platform, structure, or rig name.

(f)(1) *Drilling.* (i) When drilling on lands valuable or potentially valuable for oil and gas or geopressured or geothermal resources, drilling equipment shall be equipped with blowout prevention and control devices acceptable to the Director before penetrating more than 500 feet unless a different depth is specified in advance by the Director.

(ii) In cases where the Director determines that there is sufficient 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.

§ 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 [Reserved]

§ 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. 301 *et seq.;* 43 U.S.C. 1331.

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 *Pay.gov* at: *https://www.pay.gov/paygov/,* 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.

§ 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.

§ 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 1010–0172.

(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, 381 Elden Street, Herndon, VA 20170.

§ 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 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.

§ 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 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.

§ 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 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 Analysis at (202) 208–3530);

(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.

§ 291.108 How do I pay the processing fee?

(a) You must pay the processing fee electronically through *Pay.Gov.* The *Pay.Gov* Web site may be accessed through links on the BSEE Offshore Web site at: *http://www.bsee.gov/offshore/homepage* (on drop-down topic list) or directly through *Pay.Gov* at: *https://www.pay.gov/paygov/.*

(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.

§ 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 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 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.

§ 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.

■ 2. Add chapter V to read as follows:

CHAPTER V—BUREAU OF OCEAN ENERGY MANAGMENT, DEPARTMENT OF THE INTERIOR

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

Part

519 DISTRIBUTION AND DISBURSEMENT OF ROYALTIES, RENTALS, AND BONUSES

SUBCHAPTER B—OFFSHORE

550 OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

551 GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

552 OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM

553 OIL SPILL FINANCIAL RESPONSIBILITY FOR OFFSHORE FACILITIES

556 LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

559 MINERAL LEASING: DEFINITIONS

560 OUTER CONTINENTAL SHELF OIL AND GAS LEASING

570 NONDISCRIMINATION IN THE OUTER CONTINENTAL SHELF
580 PROSPECTING FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR ON THE OUTER CONTINENTAL SHELF
581 LEASING OF MINERALS OTHER THAN OIL, GAS, AND SULPHUR IN THE OUTER CONTINENTAL SHELF
582 OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR
585 RENEWABLE ENERGY AND ALTERNATE USES OF EXISTING FACILITIES ON THE OUTER CONTINENTAL SHELF

SUBCHAPTER C—APPEALS

590 APPEAL PROCEDURES

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

PART 519—DISTRIBUTION AND DISBURSEMENT OF ROYALTIES, RENTALS, AND BONUSES

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—[Reserved]

Subpart D—Oil and Gas, Offshore

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519.410 What does this subpart contain?
519.411 What definitions apply to this subpart?
519.412 How will the qualified OCS revenues be divided?
519.413 How will the coastal political subdivisions of Gulf producing States share in the qualified OCS revenues?
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519.415 How will bonus and royalty credits affect revenues allocated to Gulf producing States?
519.416 How will the qualified OCS revenues be allocated to coastal political subdivisions within the Gulf producing States?
519.417 How will BOEM calculate the percentage allocation of qualified OCS revenues to the coastal political subdivisions if, during any fiscal year, there are no applicable leased tracts in the 181 Area in the Eastern Gulf of Mexico Planning Area?
519.418 When will funds be disbursed to Gulf producing States and eligible coastal political subdivisions?

Authority: Section 104, Pub. L. 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Pub. L. 109–432, Div C, Title I, 120 Stat. 3000.

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—[Reserved]

Subpart D—Oil and Gas, Offshore

§ 519.410 What does this subpart contain?

(a) The Gulf of Mexico Energy Security Act of 2006 (GOMESA) directs the Secretary of the Interior to disburse a portion of the rentals, royalties, bonus, and other sums derived from certain Outer Continental Shelf (OCS) leases in the Gulf of Mexico (GOM) to the States of Alabama, Louisiana, Mississippi, and Texas (collectively identified as the Gulf producing States); to eligible coastal political subdivisions within those States; and to the Land and Water Conservation Fund. Shared GOMESA revenues are reserved for the following purposes:

(1) Projects and activities for the purposes of coastal protection, including conservation, coastal restoration, hurricane protection, and infrastructure directly affected by coastal wetland losses.

(2) Mitigation of damage to fish, wildlife, or natural resources.

(3) Implementation of a federally-approved marine, coastal, or comprehensive conservation management plan.

(4) Mitigation of the impact of OCS activities through the funding of onshore infrastructure projects.

(5) Planning assistance and administrative costs not-to-exceed 3 percent of the amounts received.

(b) This subpart sets forth the formula and methodology BOEM will use to determine the amount of revenues to be disbursed and the amount to be allocated to each Gulf producing State and each eligible coastal political subdivision. For questions related to the revenue sharing provisions in this subpart, please contact: Program Manager, Financial Management; Office of Natural Resources Revenue; P.O. Box 25165; Denver Federal Center, Building 85; MS–61210B; Denver, CO 80225–0165, or at (303) 231–3435.

§ 519.411 What definitions apply to this subpart?

Terms in this subpart have the following meaning:

181 Area means the area identified in map 15, page 58, of the Proposed Final Outer Continental Shelf Oil and Gas Leasing Program for 1997–2002, dated August 1996, of the Bureau of Ocean Energy Management, available in the Office of the Director of the Bureau of Ocean Energy Management, excluding the area offered in OCS Lease Sale 181, held on December 5, 2001.

181 Area in the Eastern Planning Area is comprised of the area of overlap of the two geographic areas defined as the ''181 Area'' and the ''Eastern Planning Area.''

181 South Area means any area—

(1) Located:

(i) South of the 181 Area;

(ii) West of the Military Mission Line; and

(iii) In the Central Planning Area;

(2) Excluded from the Proposed Final Outer Continental Shelf Oil and Gas Leasing Program for 1997–2002, dated August 1996, of the Bureau of Ocean Energy Management; and

(3) Included in the areas considered for oil and gas leasing, as identified in map 8, page 37, of the document entitled, *Draft Proposed Program Outer Continental Shelf Oil and Gas Leasing Program 2007–2012,* dated February 2006.

Applicable leased tract means a tract that is subject to a lease under section 8 of the Outer Continental Shelf Lands Act for the purpose of drilling for, developing, and producing oil or natural gas resources, and is located fully or partially in either the 181 Area in the Eastern Planning Area, or in the 181 South Area.

Central Planning Area means the Central Gulf of Mexico Planning Area of the Outer Continental Shelf, as designated in the document entitled, *Draft Proposed Program Outer Continental Shelf Oil and Gas Leasing Program 2007–2012,* dated February 2006.

Coastal political subdivision means a political subdivision of a Gulf producing State any part of which political subdivision is:

(1) Within the coastal zone (as defined in section 304 of the Coastal Zone Management Act of 1972 (16 U.S.C. 1453)) of the Gulf producing State as of December 20, 2006; and

(2) Not more than 200 nautical miles from the geographic center of any leased tract.

Coastline 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. This is the same definition used in section 2 of the Submerged Lands Act (43 U.S.C. 1301).

Distance means the minimum great circle distance.

Eastern Planning Area means the Eastern Gulf of Mexico Planning Area of the Outer Continental Shelf, as designated in the document entitled,

Draft Proposed Program Outer Continental Shelf Oil and Gas Leasing Program 2007–2012, dated February 2006.

Gulf producing State means each of the States of Alabama, Louisiana, Mississippi, and Texas.

Leased tract means any tract that is subject to a lease under section 6 or 8 of the Outer Continental Shelf Lands Act for the purpose of drilling for, developing, and producing oil or natural gas resources.

Military Mission Line means the north-south line at 86°41′ W. longitude.

Qualified OCS revenues mean:

(1) The term qualified OCS revenues means, in the case of each of fiscal years 2007 through 2016, all rentals, royalties, bonus bids, and other sums received by the U.S. from leases entered into on or after December 20, 2006, located:

(i) In the 181 Area in the Eastern Planning Area; and

(ii) In the 181 South Area.

(iii) For applicable leased tracts intersected by the planning area administrative boundary line (*e.g.,* separating the GOM Central Planning Area from the Eastern Planning Area), only the percent of revenues equivalent to the percent of surface acreage in the 181 Area in the Eastern Planning Area will be considered qualified OCS revenues.

(2) Exclusions to the term qualified OCS revenues include:

(i) Revenues from the forfeiture of a bond or other surety securing obligations other than royalties;

(ii) Civil penalties;

(iii) Royalties taken by the Secretary in-kind and not sold;

(iv) User fees; and

(v) Lease revenues explicitly circumscribed from GOMESA revenue sharing by statute or appropriations law.

§ 519.412 How will the qualified OCS revenues be divided?

For each of the fiscal years 2007 through 2016, 50 percent of the qualified OCS revenues will be placed in a special U.S. Treasury account from which 75 percent of the revenues will be disbursed to the Gulf producing States, and 25 percent will be disbursed to the Land and Water Conservation Fund. Each Gulf producing State will receive at least 10 percent of the qualified OCS revenues available for allocation to the Gulf producing States each fiscal year.

REVENUE DISTRIBUTION OF QUALIFIED OCS REVENUES UNDER GOMESA

Recipient of qualified OCS revenues	Percentage of qualified OCS revenues (percent)
U.S. Treasury (General Fund)	50
Land and Water Conservation Fund	12.5
Gulf Producing States	30
Gulf Producing State Coastal Political Subdivisions	7.5

§ 519.413 How will the coastal political subdivisions of Gulf producing States share in the qualified OCS revenues?

Of the revenues allocated to a Gulf producing State, 20 percent will be distributed to the coastal political subdivisions within that State.

§ 519.414 How will BOEM determine each Gulf producing State's share of the qualified OCS revenues?

(a) BOEM will determine the geographic centers of each applicable leased tract and, using the great circle distance method, will determine the closest distance from the geographic centers of each applicable leased tract to each Gulf producing State's coastline.

(b) Based on these distances, we will calculate the qualified OCS revenues to be disbursed to each Gulf producing State using the following procedure:

(1) For each Gulf producing State, we will calculate and total, over all applicable leased tracts, the mathematical inverses of the distances between the points on the State's coastline that are closest to the geographic centers of the applicable leased tracts and the geographic centers of the applicable leased tracts. For applicable leased tracts intersected by the planning area administrative boundary line, the geographic center used for the inverse distance determination will be the geographic center of the entire lease as if it were not intersected.

(2) For each Gulf producing State, we will divide the sum of each State's inverse distances, from all applicable leased tracts, by the sum of the inverse distances from all applicable leased tracts across all four Gulf producing States. We will multiply the result by the amount of qualified OCS revenues to be shared as shown below. In the formulas, IAL, ILA, IMS, and ITX represent the sum of the inverses of the closest distances between Alabama, Louisiana, Mississippi, and Texas and all applicable leased tracts, respectively.

Alabama Share = (IAL ÷ (IAL + ILA + IMS + ITX)) × Qualified OCS Revenues

Louisiana Share = (ILA ÷ (IAL + ILA + IMS + ITX)) × Qualified OCS Revenues

Mississippi Share = (IMS ÷ (IAL + ILA + IMS + ITX)) × Qualified OCS Revenues

Texas Share = (ITX ÷ (IAL + ILA + IMS + ITX)) × Qualified OCS Revenues

(3) If in any fiscal year, this calculation results in less than a 10 percent allocation of the qualified OCS revenues to any Gulf producing State, we will recalculate the distribution. We will allocate 10 percent of the qualified OCS revenues to the State and recalculate the other States' shares of the remaining qualified OCS revenues omitting the State receiving the 10 percent minimum share and its 10 percent share from the calculation.

§ 519.415 How will bonus and royalty credits affect revenues allocated to Gulf producing States?

If bonus and royalty credits issued under Section 104(c) of the Gulf of Mexico Energy Security Act are used to pay bonuses or royalties on leases in the 181 Area located in the Eastern Planning Area and the 181 South Area, then there will be a corresponding reduction in qualified OCS revenues available for distribution.

§ 519.416 How will the qualified OCS revenues be allocated to coastal political subdivisions within the Gulf producing States?

BOEM will calculate the percentage allocation of funds to the coastal political subdivisions in accordance with the following criteria:

(a) Twenty-five percent of the qualified OCS revenues will be allocated to a Gulf producing State's coastal political subdivisions in the proportion that each coastal political subdivision's population bears to the population of all coastal political subdivisions in the producing State;

(b) Twenty-five percent of the qualified OCS revenues will be allocated to a Gulf producing State's coastal political subdivisions in the proportion that each coastal political subdivision's miles of coastline bears to the number of miles of coastline of all coastal political subdivisions in the producing State. Except that, for the State of Louisiana, proxy coastline lengths for coastal political subdivisions without a coastline will be considered to be ⅓ the average length of the coastline of all political subdivisions within Louisiana having a coastline.

(c) Fifty percent of the revenues will be allocated to a Gulf producing State's

coastal political subdivisions in amounts that are inversely proportional to the respective distances between the geographic center of each applicable leased tract and the point in each coastal political subdivision that is closest to the geographic center of each applicable leased tract. Except that, an applicable leased tract will be excluded from this calculation if any portion of the tract is located in a geographic area that was subject to a leasing moratorium on January 1, 2005, unless that tract was in production on that date.

§ 519.417 How will BOEM calculate the percentage allocation of qualified OCS revenues to the coastal political subdivisions if, during any fiscal year, there are no applicable leased tracts in the 181 Area in the Eastern Gulf of Mexico Planning Area?

If, during any fiscal year, there are no applicable leased tracts in the 181 Area in the Eastern Gulf of Mexico Planning Area, BOEM will calculate the percentage allocation of funds to the coastal political subdivisions in accordance with the following criteria:

(a) Fifty percent of the revenues will be allocated to a Gulf producing State's coastal political subdivisions in the proportion that each coastal political subdivision's population bears to the population of all coastal political subdivisions in the State; and

(b) Fifty percent of the revenues will be allocated to a Gulf producing State's coastal political subdivisions in the proportion that each coastal political subdivision's miles of coastline bears to the number of miles of coastline of all coastal political subdivisions in the State. Except that, for the State of Louisiana, proxy coastline lengths for coastal political subdivisions without a coastline will be considered to be ⅓ the average length of the coastline of all political subdivisions within Louisiana having a coastline.

§ 519.418 When will funds be disbursed to Gulf producing States and eligible coastal political subdivisions?

(a) The Office of Natural Resources Revenue (ONRR) will disburse allocated funds in the fiscal year after it collects the qualified OCS revenues. For example, ONRR will disburse funds in fiscal year 2010 from the qualified OCS revenues collected during fiscal year 2009.

(b) ONRR intends to disburse funds on or before March 31st of the year following the fiscal year of qualified OCS revenues.

Subchapter B—OFFSHORE

PART 550—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

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Authority: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

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.

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 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.

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 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 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 air pollutant.

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.

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) 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 § 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, 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 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 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.

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.

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—550.121 [Reserved]

§ 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 a link on the BOEM Offshore Web site at: *http://www.boem.gov/offshore/* homepage or directly 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.

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) [Reserved]

(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.

§ 550.145 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.

§ 550.146 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.

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 ''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 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 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.

If . . .	BOEM 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 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.
(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,	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 § 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 §§ 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 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 or 30 CFR part 203 that BOEM uses to:

(1) [Reserved]

(2) [Reserved]

(3) [Reserved]

(4) Promote operational safety;

(5) Protect the environment; or

(6) Make field determinations.

(7) [Reserved]

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, 381 Elden Street, Herndon, VA 20170.

(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.

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.

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)).

§ 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.

§§ 550.204 550.205 [Reserved]

§ 550.206 How do I submit the EP, DPP, or DOCD?

(a) *Number of copies.* When you submit an 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 EP, DPP, or DOCD by certain affected States and other reviewing entities.

(b) *Electronic submission.* You may submit part or all of your EP, DPP, or DOCD and its accompanying information electronically. If you prefer to submit your EP, DPP, or DOCD electronically, ask the Regional Supervisor for further guidance.

(c) *Withdrawal after submission.* You may withdraw your proposed EP, DPP, or DOCD at any time for any reason. Notify the appropriate BOEM OCS Region if you do.

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 sulphur dioxide (SO_2), particulate matter in the form of PM_{10} and $PM_{2.5}$ when applicable, nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) that will be 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 of SO_2, PM, NO_X, CO, or VOC, that will be generated by your proposed exploration activities, are greater than the respective emission exemption amounts ''E'' calculated using the formulas in § 550.303(d). When BOEM requires air quality modeling, you must use the guidelines in Appendix W of 40 CFR part 51 with a model approved by the Director. 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.

§ 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

blowout, loss or disablement of a drilling unit, and loss of or damage to support craft.

(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.

§ 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 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 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 bottom-hole 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 sulphur dioxide (SO_2), particulate matter in the form of PM_{10} and $PM_{2.5}$ when applicable, nitrogen oxides (NO_X),

carbon monoxide (CO), and volatile organic compounds (VOC) that will be 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 an air pollutant 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 of SO_2, PM, NO_X, CO, or VOC that will be generated by your proposed development and production activities are greater than the respective emission exemption amounts ''E'' calculated using the formulas in § 550.303(d). When BOEM requires air quality modeling, you must use the guidelines in Appendix W of 40 CFR part 51 with a model approved by the Director. 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.

§ 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.

The regional supervisor will . . .	If . . .	And then . . .
(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 air pollutant 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.

§ 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:

Air pollutant means any combination of agents for which the Environmental Protection Agency (EPA) has established, pursuant to section 109 of the Clean Air Act, national primary or secondary ambient air quality standards.

Attainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

Best available control technology (BACT) means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account

energy, environmental and economic impacts, and other costs. The BACT shall be verified on a case-by-case basis by the Regional Supervisor and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

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

Existing facility is an OCS facility described in an Exploration Plan or a Development and Production Plan submitted or approved prior to June 2, 1980.

Facility means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities for oil, gas, or sulphur and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil, gas, or sulphur at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

Nonattainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard established by EPA.

Projected emissions 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 which is emitted to the atmosphere as a vapor. The unreactive compounds are exempt from the above definition.

§ 550.303 Facilities described in a new or revised Exploration Plan or Development and Production Plan.

(a) *New plans.* All Exploration Plans and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section, and the lessee shall comply with the requirements of this section as necessary.

(b) *Applicability of § 550.303 to existing facilities.* (1) The Regional Supervisor may review any Exploration Plan or Development and Production Plan to determine whether any facility described in the plan should be subject to review under this section and has the potential to significantly affect the air quality of an onshore area. To make these decisions, the Regional Supervisor shall consider the distance of the facility from shore, the size of the facility, the number of sources planned for the facility and their operational status, and the air quality status of the onshore area.

(2) For a facility identified by the Regional Supervisor in paragraph (b)(1) of this section, the Regional Supervisor shall require the lessee to refer to the information required in § 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 and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall comply with the requirements of this section as necessary.

(d) *Exemption formulas.* To determine whether a facility described in a new, modified, or revised Exploration Plan or Development and Production Plan is exempt from further air quality review, the lessee shall use the highest annual-total amount of emissions from the facility for each air pollutant calculated in § 550.249(a) or § 550.218(a) of this part and compare these emissions to the emission exemption amount ''E'' for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for carbon monoxide (CO); and $E=33.3D$ for total suspended particulates (TSP), sulphur dioxide (SO_2), nitrogen oxides (NO_X), and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the proposed facility from the closest onshore area of a State expressed in statute miles). If the amount of these projected emissions is less than or equal to the emission exemption amount ''E'' for the air pollutant, the facility is exempt from further air quality review required under paragraphs (e) through (i) of this section.

(e) *Significance levels.* For a facility not exempt under paragraph (d) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether the projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS—AIR POLLUTANT CONCENTRATIONS

[μg/m³]

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	.....	25	.....
TSP	1	5	.....	.....	.....
NO_2	1	.....	.....	.....	.....
CO	.....	.....	500	.....	2,000

(f) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under

paragraph (e) of this section for that air pollutant, shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(g) *Controls required.* (1) The projected emissions of any air pollutant other than VOC from any facility, except a temporary facility, which significantly affect the quality of a nonattainment area, shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(2) The projected emissions of any air pollutant other than VOC from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i) (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

[$\mu g/m^3$]

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—arithmetric.

(B) No concentration of an air pollutant shall exceed the concentration permitted under the national secondary ambient air quality standard or the concentration permitted under the national primary air quality standard, whichever concentration is lowest for the air pollutant for the period of exposure. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one onshore location.

(ii) If the maximum allowable increases are exceeded, the lessee shall apply whatever additional emission controls are necessary to reduce or offset the remaining emissions of TSP or SO_2 so that concentrations in the onshore ambient air of an attainment or unclassifiable area do not exceed the maximum allowable increases.

(3)(i) The projected emissions of VOC from any facility, except a temporary facility, which significantly affect the onshore air quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(ii) The projected emissions of VOC from any facility which significantly affect the onshore air quality of an attainment area shall be reduced through the application of BACT.

(4)(i) If projected emissions from a facility significantly affect the onshore air quality of both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to projected emissions significantly affecting a nonattainment area shall apply.

(ii) If projected emissions from a facility significantly affect the onshore air quality of more than one class of attainment area, the lessee must reduce projected emissions to meet the maximum allowable increases specified for each class in paragraph (g)(2)(i) of this section.

(h) *Controls required on temporary facilities.* The lessee shall apply BACT to reduce projected emissions of any air pollutant from a temporary facility which significantly affects the air quality of an onshore area of a State.

(i) *Emission offsets.* When emission offsets are to be obtained, the lessee must demonstrate that the offsets are equivalent in nature and quantity to the projected emissions that must be reduced after the application of BACT; a binding commitment exists between the lessee and the owner or owners of the source or sources; the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's offshore operations.

(j) *Review of facilities with emissions below the exemption amount.* If, during the review of a new, modified, or revised Exploration Plan or Development and Production Plan, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether emission control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(k) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility. The lessee shall submit this information monthly in a manner and form

approved or prescribed by the Regional Supervisor.

(l) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

§ 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 shall use the highest annual total amount of emissions from the facility for each air pollutant calculated in § 550.218(a) or § 550.249(a) of this part and compare these emissions to the emission exemption amount ''E'' for each air pollutant calculated using the following formulas: $E = 3400D^{2/3}$ for CO; and $E = 33.3D$ for TSP, SO_2, NO_X, and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the facility from the closest onshore area of the State expressed in statute miles). If the amount of projected emissions is less than or equal to the emission exemption amount ''E'' for the air pollutant, the facility is exempt for that air pollutant from further air quality review required under paragraphs (c) through (e) of this section.

(c) *Significance levels.* For a facility not exempt under paragraph (b) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS—AIR POLLUTANT CONCENTRATIONS

[μG/M³]

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	.....	25	.....
TSP	1	5	.....	.....	.....
NO_2	1	.....	.....	.....	.....
CO	.....	.....	500	.....	2,000

(d) *Significance determinations.*

(1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance levels determined under paragraph (c) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (b) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(e) *Controls required.* (1) The projected emissions of any air pollutant which significantly affect the air quality of an onshore area shall be reduced through the application of BACT.

(2) The lessee shall submit a compliance schedule for the application of BACT. If it is necessary to cease operations to allow for the installation of emission controls, the lessee may apply for a suspension of operations under the provisions of 30 CFR 250.174.

(f) *Review of facilities with emissions below the exemption amount.* If, during the review of the information required under paragraph (a)(6) of this section, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(g) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional

Supervisor, emissions from the facility following the installation of emission controls. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(h) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

Subpart D—[Reserved]

Subpart E—[Reserved]

Subpart F—[Reserved]

Subpart G—[Reserved]

Subpart H—[Reserved]

Subpart 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–140, Bottomhole Pressure Survey Report, showing a calculated bottomhole pressure or any measured data.

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) [Reserved]

(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:		
(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.

Subpart L—[Reserved]

Subpart 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 $40,000 per day per violation.

§ 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) [Reserved]

(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. The penalty may be up to $500 per 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 violations.

(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 to up to $5,000 per day, beginning with the date of the Notice of Noncompliance, for each violation for as long as you do not correct the violations.

§ 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, 801 North Quincy Street, Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

§ 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, 801 North Quincy Street, Arlington, Virginia 22203.

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 of up to $25,000 per day for each day each violation 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]

(3) [Reserved]

§ 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, 801 North Quincy Street,

Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

§ 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, 801 North Quincy, Arlington, Virginia 22203.

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: Jeffrey Walker, RS/FO, BOEM Alaska OCS Region, 3801 Centerpoint Drive, Suite 500, Anchorage, AK 99503–5823, *jeffrey.walker@boem.gov,* (907) 334–5300.

(2) For Gulf of Mexico and Atlantic OCS: Joshua Joyce, Regional FARM Program Coordinator, BOEM Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard New Orleans, LA 70123–2394, *joshua.joyce@boem.gov,* (504) 736–2779.

(3) For Pacific OCS: Jaron Ming, Lead Leasing Specialist, BOEM Pacific OCS Region, 770 Paseo Camarillo, 2nd Floor, Camarillo, CA 93010, *jaron.ming@boem.gov,* (805) 389–7514.

(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.

§ 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.

Subpart O—[Reserved]

Subpart P—[Reserved]

Subpart Q—[Reserved]

Subpart R—[Reserved]

Subpart S—[Reserved]

PART 551—GEOLOGICAL AND GEOPHYSCIAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

Sec.

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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: 31 U.S.C. 9701, 43 U.S.C. 1334.

§ 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 99503–58232.

(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, 770 Paseo Camarillo, Camarillo, California 93010–6064.

§ 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 Associate Director for BOEM.

§ 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, 381 Elden Street, Herndon, VA 20170.

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.

§ 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

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Authority: 33 U.S.C. 2716, 28 U.S.C. 2461.

Subpart A—General

§ 553.1 What is the purpose of this part?

This part establishes the requirements for demonstrating OSFR for covered offshore facilities (COFs) under Title I of the Oil Pollution Act of 1990 (OPA), as amended, 33 U.S.C. 2701 *et seq.*

§ 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.

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.

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.

Responsible party 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.

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.

§ 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, 381 Elden Street, Herndon, VA 20170.

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 $30,000 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.

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.

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 SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

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Authority: 31 U.S.C. 9701, 42 U.S.C. 6213, 43 U.S.C. 1334, Pub. L. 109–432.

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

§ 556.0 Authority for information collection.

(a) The Office of Management and Budget (OMB) has approved the information collection requirements in this part under 44 U.S.C. 3501 *et seq.* OMB assigned the control number 1010–0006. The title of this information collection is ''30 CFR part 556, Leasing of Sulphur or Oil and Gas in the Outer Continental Shelf.''

(b) BOEM collects this information to determine if the applicant filing for a lease on the Outer Continental Shelf is qualified to hold such a lease. Response is required to obtain a benefit according to 43 U.S.C. 1331 *et seq.* BOEM will protect proprietary information collected according to section 26 of the OCS Lands Act and 30 CFR 556.10.

(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, 381 Elden Street, Herndon, VA 20170.

§ 556.1 Purpose.

The purpose of the regulations in this part 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-use and easements are addressed in other parts.

§ 556.2 Policy.

The management of Outer Continental Shelf resources is to be conducted in accordance with the findings, purposes and policy directions provided by the Outer Continental Shelf Lands Act Amendments of 1978 (43 U.S.C. 1332, 1801, 1802), and other Executive, legislative, judicial and Departmental guidance. The Secretary of the Interior shall consider available environmental information in making decisions affecting Outer Continental Shelf resources.

§ 556.4 Authority.

The Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1331 *et seq.*) authorizes the Secretary of the Interior to issue, on a competitive basis, leases for oil and gas, and sulphur, in submerged lands of the outer Continental Shelf (OCS). The Act authorizes the Secretary to grant rights-of-way, rights-of-use and easements through the submerged lands of the OCS. The Energy Policy and Conservation Act of 1975 (42 U.S.C. 6213), prohibits joint bidding by major oil and gas producers.

§ 556.5 Definitions.

As used in this part, the term:

(a) *Act* refers to the Outer Continental Shelf Lands Act of August 7, 1953 (43 U.S.C. 1331 *et seq.*) as amended.

(b) *Director* means the Director, Bureau of Ocean Energy Management.

(c) *OCS* means the Outer Continental Shelf, as that term is defined in 43 U.S.C. 1331(a).

(d) *Secretary* means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

(e) *BOEM* means Bureau of Ocean Energy Management.

(f) *Coastal zone* means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States, and includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches, which zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shore lines to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454(b)(1));

(g) *Affected State* means, with respect to any program, plan, lease sale, or other activity, proposed, conducted, or approved pursuant to the provisions of the act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2) of the Act, to be the law of the United States for the portion of the Outer Continental Shelf on which such activity is, or is proposed to be conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or structure referred to in section 4(a)(1) of the Act;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted

from the Outer Continental Shelf and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the Outer Continental Shelf; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities;

(h) *Marine environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the Outer Continental Shelf;

(i) *Coastal environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone;

(j) *Human environment* means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the Outer Continental Shelf;

(k) *Mineral* means oil, gas, and sulphur; it includes sand and gravel and salt used to facilitate the development and production of oil, gas, or sulphur.

(l) *Authorized officer* means any person authorized by law or by delegation of authority to or within BOEM to perform the duties described in this part.

(m) *Bonus or royalty credit* means a legal instrument or other written documentation, 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—

(1) A bonus due for a lease on the Outer Continental Shelf; or

(2) A royalty due on oil or gas production from any lease located on the Outer Continental Shelf.

(n) *Central planning area* means the Central Gulf of Mexico Planning Area of the Outer Continental Shelf, as designated in the document entitled ''Draft Proposed Program Outer Continental Shelf Oil and Gas Leasing Program 2007–2012,'' dated February 2006.

(o) *Coastline* means the line of 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.

(p) *Desoto Canyon OPD* means the official protraction diagram designated as Desoto Canyon which has a western edge located at the universal transverse mercator (UTM) X coordinate 1,346,400 in the North American Datum of 1927 (NAD 27).

(q) *Destin Dome OPD* means the official protraction diagram designated as Destin Dome which has a western edge located at the universal transverse mercator (UTM) X coordinate 1,393,920 in the NAD 27.

(r) *Eastern planning area* means the Eastern Gulf of Mexico Planning Area of the Outer Continental Shelf, as designated in the document entitled ''Draft Proposed Program Outer Continental Shelf Oil and Gas Leasing Program 2007–2012,'' dated February 2006.

(s) *Pensacola OPD* means the official protraction diagram designated as Pensacola which has a western edge located at the universal transverse mercator (UTM) X coordinate 1,393,920 in the NAD 27.

§ 556.7 Cross references.

(a) For Bureau of Ocean Energy Management regulations governing exploration, development and production on leases, see 30 CFR parts 550 and 570.

(b) For BOEM regulations governing the appeal of an order or decision issued under the regulations in this part, see 30 CFR part 590.

(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.

§ 556.8 Leasing maps and diagrams.

(a) Any area of the OCS which has been appropriately platted as provided in paragraph (b) of this section, is subject to lease for any mineral not included in a subsisting lease issued under the act or meeting the requirements of subsection (a) of section 6 of the Act. Before any lease is offered or issued an area may be:

(1) Withdrawn from disposition pursuant to section 12(a) of the Act; or

(2) Designated as an area or part of an area restricted from operation under section 12(d) of the Act.

(b) BOEM shall prepare leasing maps and official protraction diagrams of areas of the OCS. The areas included in each mineral lease shall be in accordance with the appropriate leasing map or official protraction diagram.

§ 556.10 Information to States.

(a) The information covered in this section is prepared by or directly obtained by the Director. Such information is typically not considered to be proprietary or privileged, with the primary exception of specific indications of interest in an area by industry received in response to a Call for Information issued by the Secretary. This information and all other proprietary and privileged information obtained by or under the control of the Bureau of Ocean Energy Management may be released only in accordance with the regulations in 30 CFR parts 550, 551, and 552.

(b) The Director shall prepare an index to OCS information (see 30 CFR 552.5). The index shall list all relevant actual or proposed programs, plans, reports, environmental impact statements, nominations information, environmental study reports, lease sale information and any similar type of relevant information including, modifications, comments and revisions, prepared by or directly obtained by the Director under the act. The index shall be sent on a regular basis to affected States and, upon request, it shall be sent to any affected local government. The

public shall be informed of the availability of the index.

(c) Upon request, the Director shall transmit to affected States, local governments or the public, a copy of any information listed in the index which is subject to the control of the BOEM in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and regulations implementing said Act, and the regulations contained in 43 CFR part 2, except as provided in paragraph (d) of this section.

(d) Upon request, the Director shall provide relative indications of interest in areas as well as any comments filed in response to a Call for Information for a proposed sale. However, no information transmitted shall identify any particular area with the name of any particular party so as not to compromise the competitive position of any participants in the process of indicating interest.

§ 556.11 Helium.

(a) Each lease issued or continued under these regulations shall be subject to a reservation by the United States, under section 12(f) of the Act, of the ownership of and the right to extract helium from all gas produced from the leased area.

(b) In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area or at an onshore processing facility. Delivery shall be made in the manner required by the United States to such plants or reduction works as the United States may provide.

(c) The extraction of helium shall not cause a reduction in the value of the lessee's gas or any other loss for which he is not reasonably compensated, except for the value of the helium extracted. The United States shall determine the amount of reasonable compensation. The United States shall have the right to erect, maintain and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium. The extraction of helium shall not cause substantial delays in the delivery of natural gas produced to the purchaser of that gas.

§ 556.12 Supplemental sales.

(a) The Secretary may conduct a supplemental sale in accordance with the provisions of this section.

(b) Supplemental sales shall be governed by the regulations in this part, except § 556.22.

(c) Supplemental sales shall be limited to blocks falling into one or more of the following categories:

(1) Blocks for which bids were rejected during the calendar year preceding the year of the supplemental sale in which they are reoffered or blocks for which bids were rejected in the same calendar year as the supplemental sale in which they are reoffered, except that for the initial supplemental sale only blocks for which bids were rejected after October 1, 1987, may be reoffered. If, after the initial supplemental sale, a supplemental sale is not held annually for any reason, the relevant period for determining blocks eligible for a subsequent supplemental sale may be extended to include rejected bid blocks which were eligible for the supplemental sale not held.

(2) Blocks for which the high bid was forfeited during the calendar year preceding the year of the supplemental sale in which they are reoffered or blocks for which high bids were forfeited in the same calendar year as the supplemental sale in which they are reoffered, except that for the initial supplemental sale only blocks for which high bids were forfeited after October 1, 1987, may be reoffered. If, after the initial supplemental sale, a supplemental sale is not held annually for any reason, the relevant period for determining blocks eligible for a subsequent sale may be extended to include forfeited bid blocks which were eligible for the supplemental sale not held.

(3) Development blocks. Development blocks (including blocks susceptible to drainage) are blocks which are located on the same general geologic structure as an existing lease having a well with indicated hydrocarbons; the reservoir may or may not be interpreted to extend on to the block.

(d) Supplemental sales shall not include blocks in the Central or Western Gulf of Mexico Planning Areas.

(e) The Director may disclose the classification of blocks in supplemental sales as development blocks.

Subpart B—Oil and Gas Leasing Program

§ 556.16 Receipt and consideration of nominations; public notice and participation.

(a) During preparation of a proposed 5-year leasing program, the Secretary shall invite and consider suggestions and relevant information for such program from Governors of affected States, local government, industry, other Federal agencies, including the Attorney General in consultation with the Federal Trade Commission, and all interested parties, including the general public. This request for information shall be issued as a notice in the **Federal Register**. Local governments wishing to respond to such request shall first submit their responses to the Governor of the State in which the local government is located.

(b) The Secretary shall send letters to the Governors of the affected States requesting them to identify specific laws, goals, and policies which they believe should be considered by the Secretary in connection with the leasing program. The Secretary shall also request from the Secretary of Energy information on regional and national energy markets, on OCS production goals and on transportation networks.

§ 556.17 Review by State and local governments and other persons.

(a)(1) The Secretary shall prepare a proposed leasing program. At least 60 days prior to publication of the proposed program in the **Federal Register**, a copy of the draft of the proposed program shall be forwarded to the Governor of each affected State for comment. The Governor may solicit comments from local governments in his or her State which the Governor determines will be affected by the proposed program.

(2) The Secretary shall reply in writing to any comment on the draft of the proposed program from the Governor of an affected State which is received at least 15 days prior to the submission of the proposed program to the Congress and publication in the **Federal Register**. All such correspondence between the Secretary and Governor of such State shall accompany the proposed program when it is submitted to the Congress.

(b) The proposed leasing program shall be submitted to the Governors of the affected States for review and comment at the time it is submitted to the Congress and the Attorney General and published in the **Federal Register**. The Governor of an affected State shall, upon request from any local government affected by the program, submit a copy of the proposed program to such local government. Comments and recommendations on any aspect of the proposed program may be submitted by a State or local government or other persons to the Secretary within 90 days after the date of its publication in the **Federal Register**. Comments and recommendations from local governments shall be submitted first to the Governor of the State in which the local government is located.

(c) At least 60 days prior to approving the final leasing program and any later significant revision, the Secretary shall submit it to the President and the Congress, together with any comments. The Secretary shall indicate in such submission why any specific recommendation of the Attorney General or of a State or local government was not accepted.

§ 556.19 Periodic consultation with interested parties.

The Secretary shall provide for periodic consultation with State and local governments, existing and potential oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in any activity in or on the OCS, including those involved in fish and shellfish recovery, and recreational activities. This consultation shall take place primarily through appropriate public notice as described in §§ 556.16 and 556.17 and through the OCS Advisory Board and its committees, on a regional and National basis. Meetings of the OCS Advisory Board shall be held on specific issues as required by the Board's charter.

§ 556.20 Consideration of coastal zone management program.

In the development of the leasing program, consideration shall be given to the coastal zone management program being developed or administered by an affected coastal State under section 305 or 306 of the Coastal Zone Management Act of 1972 as amended, (16 U.S.C. 1454, 1455). Information concerning the relationship between a State's coastal zone management program and OCS oil and gas activity shall be requested from the Governors of the affected coastal States and from the Secretary of Commerce prior to the development of the proposed leasing program at the time information is requested under § 556.16 of this part.

Subpart C—Reports From Federal Agencies

§ 556.22 General.

For oil and gas lease sales shown in an approved leasing schedule and as the need arises for other mineral leasing, the Director shall prepare a report describing the general geology and potential mineral resources of the area under consideration. The Director may request other interested Federal Agencies to prepare reports describing, to the extent known, any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment or other uses of the area.

Subpart D—Call for Information and Nominations

§ 556.23 Information on areas.

(a) The Director may receive and consider indications of interest in areas for mineral leasing.

(b) In accordance with an approved program and schedule for the leasing of OCS lands which may contain oil and gas, the Director shall issue Calls for Information and Nominations on areas for leasing of such minerals in specified areas. The Call for Information and Nominations shall be published in the **Federal Register** and may be published in other publications as desirable. Information on areas shall be addressed to the appropriate BOEM regional supervisor with a copy to any other office which may be specified in the Call. The Director shall also request comments on areas which should receive special concern and analysis. For an oil and gas lease sale Call Area, the Director may request comments concerning geological conditions, including bottom hazards; archaeological sites on the seabed or near shore; multiple uses of the proposed leasing area, including navigation, recreation, and fisheries; and other socioeconomic, biological, and environmental information.

§ 556.25 Areas near coastal States.

(a) At the time information is solicited for leasing of areas within 3 geographical miles seaward of the seaward boundary of any coastal State, the Secretary shall provide the Governor of that State information required under section 8(g)(1) of the Act. The Director shall furnish information identifying the areas for leasing as well as all relevant available environmental data for such areas (See 30 CFR 551.14).

(b) After receipt of information on areas within the area described in paragraph (a) of this section, the Secretary shall inform the Governor of those areas that are to be given further consideration for leasing. The Secretary shall enter into consultation with the Governor to determine whether the area may contain oil or gas pools or fields underlying both the OCS and lands subject to the jurisdiction of the State.

(c) After selection for leasing of those tracts which may have oil or gas pools or fields underlying both the OCS and lands under State jurisdiction, the Secretary shall offer the Governor an opportunity to enter into an agreement for the equitable disposition of revenues from such tracts under section 8(g)(2) of the Act.

(d) If no agreement can be reached within 90 days of the Secretary's offer, the tracts may be leased and all revenues deposited in a separate Treasury account pending equitable disposition of the revenues under sections 8(g)(3) and (4) of the Act.

Subpart E—Area Identification and Tract Size

§ 556.26 General.

(a) The Director, in consultation with appropriate Federal Agencies, shall recommend to the Secretary areas identified for environmental analysis and consideration for leasing. The Director, on his/her own motion, may include in the recommendation areas in which interest has not been indicated in response to a call. In making a recommendation, the Director shall consider all available environmental information, multiple-use conflicts, resource potential, industry interest and other relevant information. Comments received from States and local governments and interested parties in response to calls for information and nominations shall be considered in making recommendations. For supplemental sales provided for by § 556.12 of this part, the Director's recommendation shall be replaced by a statement describing the results of the Director's consideration of the factors specified above in this section.

(b) The Director shall evaluate fully the potential effect of leasing on the human, marine and coastal environments, and develop measures to mitigate adverse impacts, including lease stipulations. The views and recommendations of Federal agencies, State agencies, local governments, organizations, industries and the general public shall be used as appropriate. The Director may hold public hearings on the environmental analysis after appropriate notice.

(c) In general, the Director shall seek to inform the public as soon as possible of additions or deletions that occur after the identification of areas.

§ 556.28 Tract size.

(a) A tract selected for oil and gas leasing shall consist of a compact area not exceeding 5,760 acres, unless the authorized officer finds that a larger area is necessary to comprise a reasonable economic production unit.

(b) The tract size for the leasing of other minerals shall be specified in the notice of sale.

Subpart F—Lease Sales

§ 556.29 Proposed notice of sale.

(a) The Director shall in consultation with appropriate Federal agencies develop measures, including lease stipulations and conditions, to mitigate adverse impacts on the environments. For oil and gas lease sales, appropriate proposed stipulations and conditions shall be contained or referenced in the proposed notice of lease sale.

(b) A proposed notice of lease sale shall be submitted to the Secretary for approval. All comments and recommendations received and the Director's findings or actions thereon, shall also be forwarded to the Secretary.

(c) Upon approval by the Secretary, the proposed Notice of Sale shall be sent to the Governor of any affected State and a notice of its availability shall be published in the **Federal Register**.

§ 556.31 State comments.

(a) Within 60 days after notice of a proposed lease sale, a Governor of any affected State or any affected local government in such State may submit recommendations to the Secretary regarding the size, timing or location of the proposed lease sale. Prior to submitting recommendations to the Secretary, any affected local government shall forward such recommendation to the Governor.

(b) The Secretary shall accept such recommendations of the Governor and may accept recommendations of any affected local government if he determines, after having provided the opportunity for consultation, that they provide for a reasonable balance between the National interest and the well-being of the citizens of the affected State. A determination of the National interest shall be based on the findings, purposes and policies of the Act.

(c) The Secretary shall communicate to the Governor, in writing, the reasons for his determination to accept or reject such Governor's recommendations, or to implement any alternative means identified in consultation with the Governor to provide for a reasonable balance between the National interest and the well-being of the citizens of the affected State.

§ 556.32 Notice of sale.

(a) Upon approval of the Secretary, the Director shall publish the notice of lease sale in the **Federal Register** as the official publication, and may publish the notice in other publications. The publication in the **Federal Register** shall be at least 30 days prior to the date of the sale. The notice shall state the place and time at which bids shall be filed, and the place, date and hour at which bids shall be opened. The notice shall contain or reference a description of the areas to be offered for lease and any stipulations, terms and conditions of the sale.

(b) Tracts shall be offered for lease by competitive sealed bidding under conditions specified in the notice of lease sale and in accordance with all applicable laws and regulations. A suggested format for bidder submissions appears in the appendix to this part.

(c) The notice of lease sale shall contain a reference to the OCS lease form which shall be issued to successful bidders.

(d) With the approval of the Secretary, the Director may defer any part of the payment of the cash bonus according to a schedule announced at the time of the notice of lease sale. Payment shall be made no later than 5 years after the date of the lease sale. The schedule shall contain provisions for guaranteed payment of a deferred bonus.

(e) In order to obtain statistical information to determine which bidding alternatives best accomplish the purposes and policies of the Act, the Director may, until September 18, 1983, require each bidder to submit bids for any OCS area in accordance with more than one of the bidding systems described in section 8(a)(1) of the Act. No more than 10 percent of the tracts offered each year shall contain such a requirement. Leases may be awarded using a bidding alternative selected at random for statistical purposes, if it is otherwise consistent with the purposes and policies of the Act.

Subpart G—Issuance of Leases

§ 556.35 Qualifications of lessees.

(a) In accordance with section 8 of the Act, leases shall be awarded only to the highest responsible qualified bidder.

(b) Mineral leases issued pursuant to section 8 of the Act may be held only by:

(1) Citizens and nationals of the United States;

(2) Aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20);

(3) Private, public or municipal corporations organized under the laws of the United States or of any State or of the District of Columbia or territory thereof; or

(4) Associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

(c) BOEM may disqualify you from acquiring any new lease holdings or lease assignments if your operating performance is unacceptable according to 30 CFR 550.135.

§ 556.37 Lease term.

(a)(1) All oil and gas leases shall be issued for an initial period of 5 years, or not to exceed 10 years where the authorized officer finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions.

(2) If your oil and gas lease is in water depths between 400 and 800 meters, it will have an initial lease term of 8 years unless BOEM establishes a different lease term under paragraph (a)(1) of this section.

(3) For leases issued with an initial term of 8 years, you must begin an exploratory well within the first 5 years of the term to avoid lease cancellation.

(b) An oil and gas lease shall continue after such initial period for as long as oil or gas is produced from the lease in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted. The term of an oil and gas lease is subject to further extension as provided in 30 CFR 556.73.

(c) Sulphur leases shall be issued for a term not to exceed 10 years and so long thereafter as sulphur is produced from the leasehold in paying quantities, or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

§ 556.38 Joint bidding provisions.

§ 556.40 Definitions.

The following definitions apply to §§ 556.38 through 556.44 of this part.

(a) *Single bid* means a bid submitted by one person for an oil and gas lease under section 8(a) of the Act.

(b) *Joint bid* means a bid submitted by two or more persons for an oil and gas lease under section 8(a) of the Act.

(c) *Average daily production* is the total of all production in an applicable production period which is chargeable under § 556.43 of this title divided by the exact number of calendar days in the applicable production period.

(d) *Barrel* means 42 U.S. gallons.

(e) *Crude oil* means a mixture of liquid hydrocarbons including condensate that exists in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities, but does not include liquid hydrocarbons produced from tar sand, gilsonite, oil shale, or coal.

(f) *An economic interest* means any right to, or any right dependent upon,

production of crude oil, natural gas, or liquefied petroleum products and shall include, but not be limited to, a royalty interest, or overriding royalty interest, whether payable in cash or in kind, a working interest, a net profits interest, a production payment, or a carried interest.

(g) *Liquefied petroleum products* means natural gas liquid products including the following: ethane, propane, butane, pentane, natural gasoline, and other natural gas products recovered by a process of absorption, adsorption, compression, or refrigeration cycling, or a combination of such processes.

(h) *Natural gas* means a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist in the gaseous phase.

(i) *Oil and gas lease* means an oil and gas lease either offered or issued pursuant to the provisions of the Act.

(j) *Owned* means:

(1) *With respect to crude oil* —having either an economic interest in or a power of disposition over the production of crude oil;

(2) *With respect to natural gas*—having either an economic interest in or a power of disposition over the production of natural gas; and

(3) *With respect to liquefied petroleum products*—having either an economic interest in or a power of disposition over any liquefied petroleum product at the time of completion of the liquefaction process.

(k) *Prior production period* means the continuous 6-month period of January 1 through June 30 preceding November 1 through April 30 for joint bids submitted during the 6-month bidding period from November 1 through April 30, and means the continuous 6-month period of July 1 through December 31 preceding May 1 through October 31 for joint bids submitted during the 6-month bidding period from May 1 through October 31.

(l) *Production:* (1) *Of crude oil* means the volume of crude oil produced worldwide from reservoirs during the prior production period. The amount of such crude oil production shall be established by measurement of volumes delivered at the point of custody transfer (*e.g.,* from storage tanks to pipelines, trucks, tankers, or other media for transport to refineries or terminals) with adjustments for:

(i) Net differences between opening and closing inventories, and

(ii) Basic sediment and water;

(2) *Of natural gas* means the volume of natural gas produced worldwide from natural oil and gas reservoirs during the prior production period, with adjustments, where applicable, to reflect

(i) The volume of gas returned to natural reservoirs; and

(ii) The reduction of volume resulting from the removal of natural gas liquids and nonhydrocarbon gases.

(3) *Of liquefied petroleum products* mean the volume of natural gas liquids produced from reservoir gas and liquefied at surface separators, field facilities, or gas processing plants worldwide during the prior production period; these liquefied petroleum products include the following:

(i) *Condensate*—natural gas liquids recovered from gas well gas (associated and non-associated) in separators or field facilities;

(ii) *Gas plant products*—natural gas liquids recovered from natural gas in gas processing plants and from field facilities. Gas plant products shall include the following as classified according to the standards of the Natural Gas Processors Association (NGPA) or the American Society for Testing and Materials (ASTM):

(A) Ethane—C_2H_6

(B) Propane—C_3H_8

(C) Butane—C_4H_{10} including all products covered by NGPA specifications for commercial butane.

(*1*) Isobutane,

(*2*) Normal butane,

(*3*) Other butanes—all butanes not included as isobutane or normal butane;

(D) Butane-Propane Mixtures—All products covered by NGPA specifications for butane-propane mixtures;

(E) Natural Gasoline—A mixture of hydrocarbons extracted from natural gas, which meet vapor pressure, end point, and other specifications for natural gasoline set by NGPA;

(F) Plant Condensate—A natural gas plant product recovered and separated as a liquid at gas inlet separators or scrubbers in processing plants or field facilities; and

(G) Other Natural Gas Plant Products meeting refined product standards (*i.e.,* gasoline, kerosene, distillate, *etc.*).

(m) *6-month bidding period* means the 6-month period of time:

(1) From May 1 through October 31; or

(2) From November 1 through April 30, respectively.

§ 556.41 Joint bidding requirements.

(a) Any person who submits a joint bid for any oil and gas lease during a 6-month bidding period, and who was chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquefied petroleum products, shall have filed under oath with the Director, a Statement of Production of crude oil, natural gas and liquefied petroleum products, hereinafter referred to as a Statement of Production, no later than 45 days prior to the commencement of the applicable 6-month bidding period of May 1 through October 31, and November 1 through April 30. Statements of Production shall be submitted to the Director, BOEM (Attention: Offshore Leasing Management Division), Washington, DC 20240. The Statement of Production shall indicate that the person was chargeable, in accordance with § 556.43 of this part, with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquefied petroleum products for the prior production period. The Director shall publish semi-annually in the **Federal Register** a ''List of Restricted Joint Bidders'' to be effective immediately upon publication and to continue in force and effect until a subsequent list is published. The ''List of Restricted Joint Bidders'' shall consist of those persons, who in the judgment of the Director, based on information available to him, including, but not limited to, sworn Statements of Production, are chargeable under § 556.43 of this part with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquefied petroleum products for the prior production period.

(b) When a person is placed on the List of Restricted Joint Bidders the Director shall serve that person either personally or by certified mail, return receipt requested, with a copy of the Director's Order placing that person on the List of Restricted Joint Bidders. Any appeal from that Order or from an adverse effect of that Order shall be made in accordance with the provisions of 43 CFR part 4.

(c) The submission of a Statement of Production or of a detailed Report of Production under § 556.46(g) of this part which misrepresents the chargeable production of the reporting person shall constitute failure to comply with these regulations and any lease awarded in reliance on that Statement or Report of Production may be canceled, pursuant to section 8(o) of the Act and regulations issued there under as having been obtained by fraud or misrepresentation.

(d) The Secretary may exempt a person from the provisions of §§ 556.41(a), 556.44, 556.46(g) and 556.62(b) of this part if it is found, on the record, after an opportunity for an agency hearing, that lands being offered have extremely high cost exploration and development problems and that

exploration and development will not occur on such lands unless the exemption is granted.

§ 556.43 Chargeability for production.

(a) As used in this section the following definitions shall control:

(1) *Person* means a natural person or company.

(2) *Company* means a corporation, a partnership, an association, a joint-stock company, a trust, a fund, or any group of persons whether incorporated or not; it also means any receiver, trustee in bankruptcy, or similar official acting for such a company.

(3) *Subsidiary* means a company 50 percent or more of whose stock or other interest having power to vote for the election of directors, trustees, or other similar controlling body of the company is directly or indirectly owned, controlled, or held with the power to vote by another company; a subsidiary shall be deemed a subsidiary of the other company owning, controlling, or holding 50 percent or more of the stock or other voting interest.

(4) *Security or securities* means any note, stock, treasury stock, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateral-trust certificate, pre-organization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, or, in general, any interest or instrument commonly known as a ''security'' or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase any of the foregoing.

(b) A person filing a Statement of Production under § 556.41 of this part shall be charged with the following production during the applicable prior production period:

(1) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products which it owned worldwide;

(2) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every subsidiary of the reporting person;

(3) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(4) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

(c) A person filing a Statement of Production shall be charged with, in addition to the production chargeable under paragraph (b) of this section, but not in duplication thereof, its proportionate share of the average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every person:

(1) Which has an interest in the reporting person, and

(2) In which the reporting person has an interest, whether the interest referred to in paragraphs (c)(1) and (2) of this section is by virtue of ownership of securities or other evidence of ownership, or by participation in any contract, agreement, or understanding respecting the control of any person or of any person's production of crude oil, natural gas, or liquefied petroleum products, equal to said interest. As used in paragraph (c) of this section ''interest'' means an interest of at least 5 percent of the ownership or control of a person.

(d) All measurements of crude oil and liquefied petroleum products under this section shall be at 60 °F.

(e)(1) For purposes of computing production of natural gas under § 556.41 of this part, chargeability under this section, and reporting under § 556.46(g) of this part, 5,626 cubic feet of natural gas at 14.73 pounds per square inch (msl) shall equal one barrel.

(2) For purposes of computing production of liquefied petroleum products under § 556.41 of this part, chargeability under § 556.46(g) of this part, 1.454 barrels of natural gas liquids at 60 °F shall equal one barrel of crude oil.

§ 556.44 Bids disqualified.

The following bids for any oil and gas lease shall be disqualified and rejected in their entirety:

(a) A joint bid submitted by 2 or more persons who are on the effective List of Restricted Joint Bidders; or

(b)(1) A joint bid submitted by two or more persons when 1 or more of those persons is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquefied petroleum products and has not filed a Statement of Production as required by § 556.41 of this part for the applicable 6-month bidding period, or

(2) Any of those persons have failed or refused to file a detailed report of production when required to do so under § 556.46(g) of this part, or

(c) A single or joint bid submitted pursuant to an agreement (whether written or oral, formal or informal, entered into or arranged prior to or simultaneously with the submission of such single or joint bid, or prior to or simultaneously with the award of the bid upon the tract) which provides:

(1) For the assignment, transfer, sale, or other conveyance of less than a 100 percent interest in the entire tract on which the bid is submitted, by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or

(2) For the assignment, sale, transfer or other conveyance of less than a 100 percent interest in any fractional interest in the entire tract (which fractional interest was originally acquired by the person making the assignment, sale, transfer or other conveyance, under the provisions of the act) by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or

(3) For the assignment, sale, transfer, or other conveyance of any interest in a tract by a person or persons not on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to 2 or more persons on the same List of Restricted Joint Bidders; or

(4) For any of the types of conveyances described in paragraphs (c)(1), (2) or (3) of this section where any party to the conveyance is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquefied petroleum products and has not filed a Statement of Production pursuant to § 556.41 of this part for the applicable 6-month bidding period. Assignments expressly required by law, regulation, lease or stipulation to lease shall not disqualify an otherwise qualified bid; or

(d) A bid submitted by or in conjunction with a person who has filed a false, fraudulent or otherwise intentionally false or misleading detailed Report of Production.

§ 556.46 Submission of bids.

(a) A separate sealed bid shall be submitted for each tract unit bid upon as described in the notice of lease sale. A bid may not be submitted for less than an entire tract.

(b) BOEM requires a deposit for each bid. The notice of sale will specify the

bid deposit amount and method of payment.

(c) If the bidder is an individual a statement of citizenship shall accompany the bid.

(d) If the bidder is an association (including a partnership), the bid shall be accompanied by a certified statement indicating the State in which it is registered and that it is authorized to hold mineral leases on the OCS, or appropriate reference to statements or records previously submitted to a BOEM OCS office (including material submitted in compliance with prior regulations).

(e) If the bidder is a corporation, the following information shall be submitted with the bid:

(1) A statement certified by the corporate Secretary or Assistant Secretary over the corporate seal showing the State in which it was incorporated and that it is authorized to hold mineral leases on the OCS, or appropriate reference to statements or records previously submitted to 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 either a certified copy of the minutes of the board of directors or of the bylaws indicating that the person signing has authority to do so; or a certificate to that effect signed by the Secretary or Assistant Secretary of the corporation over the corporate seal, or appropriate reference to statements or records previously submitted to 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.

(f) Bidders should be aware of the provisions of 18 U.S.C. 1860, prohibiting unlawful combination or intimidation of bidders.

(g) To verify the accuracy of any statement submitted pursuant to § 556.41 of this part, the Director may require the person submitting such information to:

(1) Submit no later than 30 days after receipt of the request by the Director, a detailed Report of Production which shall list, in barrels, the average daily production of crude oil, natural gas and liquefied petroleum products chargeable to the reporting person in accordance with § 556.43 of this part for the prior production period, and

(2) Permit the inspection and copying by an official of the Department of the Interior of such documents, records of production of crude oil, natural gas and liquefied petroleum products, analyses and other material as are necessary to demonstrate the accuracy of any statement or information contained in any Report of Production.

(h) No bid for a lease may be submitted if the Secretary finds, after notice and hearing, that the bidder is not meeting due diligence requirements on other OCS leases.

§ 556.47 Award of leases.

(a) Sealed bids received in response to the notice of lease sale shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids shall be accepted or rejected at that time.

(b) The United States reserves the right to reject any and all bids received for any tract, regardless of the amount offered.

(c) In the event the highest bids are tie bids, the tie bidders (unless they would be disqualified under § 556.35(b) of this part, or disqualified under § 556.44 of this part if their bids had been joint bids) may file with the Director, within 15 days after notification, an agreement to accept the lease jointly; otherwise all bids shall be rejected.

(d) Pursuant to section 8(c) of the Act, the Attorney General may review the results of the lease sale prior to the acceptance of bids and issuance of leases.

(e)(1) The decision of the authorized officer on bids shall be the final action of the Department, subject only to reconsideration by the Secretary, pursuant to written request, of the rejection of the high bid. The delegation of review authority to the Office of Hearings and Appeals shall not be applicable to decisions on high bids for leases on the Outer Continental Shelf.

(2) The authorized officer must accept or reject the bid within 90 days. The authorized officer may extend the time period for acceptance or rejection of a bid for 15 working days or longer, if circumstances warrant. Any bid not accepted within the prescribed time period, including any extension thereof, is deemed rejected.

(3) Any high bidder whose bid is rejected by the authorized officer may, within 15 days of such rejection, file with the Secretary, with a copy to the authorized officer, a written request for reconsideration accompanied by a statement of reasons. The Secretary shall respond in writing either affirming or reversing the decision of the authorized officer.

(f) Written notice of the authorized officer's action shall be transmitted promptly to those bidders whose deposits have been held. If a bid is accepted, such notice shall transmit three copies of the lease to the successful bidder. As provided in 30 CFR 1218.155, the bidder shall, not later than the 11th business day after receipt of the lease, execute the lease, pay the first-year's rental, and unless deferred, pay the balance of the bonus bid. The bidder must also file a bond as required in § 556.52 of this title. Deposits and any interest accrued shall be refunded on high bids subsequently rejected.

(g) If the successful bidder fails to execute the lease within the prescribed time or otherwise comply with the applicable regulations the deposit shall be forfeited and disposed of as other receipts under the Act.

(h) If, before the lease is executed on behalf of the United States, the land which would be subject to the lease is withdrawn or restricted from leasing, all deposits and any interest due shall be refunded.

(i) If the awarded lease is executed by an agent acting on behalf of the bidder, the lease shall be accompanied by evidence that the bidder authorized the agent to execute the lease. When three copies of the lease are executed and returned to the authorized officer, the lease shall be executed on behalf of the United States, and one fully executed copy shall be transmitted to the successful bidder.

(j) No lease or permit shall be issued for any area within 15 statute miles of the boundaries of the Point Reyes Wilderness in California unless the State of California allows exploration, development or production activities in the adjacent navigable waters of the State under section 11(h) of the Act.

§ 556.49 Lease form.

Oil and gas leases and leases for sulphur shall be issued on forms approved by the Director. Other mineral leases shall be issued on such forms as may be prescribed by the Secretary.

§ 556.50 Dating of leases.

All leases issued under the regulations in this part shall be dated and become effective as of the first day of the month following the date leases are signed on behalf of the lessor. When prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart H—Rentals and Royalties [Reserved]

Subpart I—Bonding

§ 556.52 Bond requirements for an oil and gas or sulphur lease.

This section establishes bond requirements for the lessee of an OCS oil and gas or sulphur lease.

(a) Before 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 areawide bond that guarantees compliance with all the terms and conditions of all your oil and gas and sulphur leases in the area where the lease is located; or

(3) Maintain a lease or area wide bond in the amount required in § 556.53(a) or (b) of this part.

(b) For the purpose of this section, there are three areas. The area offshore the Atlantic Coast is included in the Gulf of Mexico. Areawide bonds issued in the Gulf of Mexico will cover oil and gas or sulphur operations offshore the Atlantic Coast. 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 instruments) under paragraph (a)(1) of this section and § 556.53(a) and (b) is satisfied if your operator provides a lease bond in the required amount that guarantees compliance with all the terms and conditions of the lease. Your operator may 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 U.S. Department of the Treasury (Treasury) securities instead of a bond. The Treasury securities you pledge must be negotiable for an amount of cash equal to the value of the bond they replace.

(1) If you pledge Treasury securities under this paragraph (f), you must monitor their value. If their market value falls below the level of bond coverage required under this subpart, you must pledge additional Treasury securities to raise the value of the securities pledged to the required amount.

(2) If you pledge Treasury securities, you must include authority for the Regional Director to sell them and use the proceeds when the Regional Director determines that you fail to satisfy any lease obligation.

(g) You may pledge 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.

§ 556.53 Additional bonds.

(a) This paragraph explains what bonds the lessee must provide before lease exploration activities commence.

(1)(i) You must furnish the Regional Director a $200,000 bond that guarantees compliance with all the terms and conditions of the lease by the earliest of:

(A) The date you submit a proposed Exploration Plan (EP) for approval;

(B) The date you submit a request for approval of the assignment of a lease on which an EP has been approved; or

(C) December 8, 1997, for any lease for which an EP has been approved.

(ii) The Regional Director may authorize you to submit the $200,000 lease exploration bond after you submit an EP but before he/she approves drilling activities under the EP.

(iii) You may satisfy the bond requirement of this paragraph (a) by providing a new bond or by increasing the amount of your existing bond.

(2) A $200,000 lease exploration bond pursuant to paragraph (a)(1) of this section need not be submitted and maintained if the lessee either:

(i) Furnishes and maintains an areawide bond in the sum of $1 million issued by a qualified surety and conditioned on compliance with all the terms and conditions of oil and gas and sulphur leases held by the lease on the OCS for the area in which the lessee is situated; or

(ii) Furnishes and maintains a bond pursuant to paragraph (b)(2) of this section.

(b) This paragraph explains what bonds you (the lessee) must provide before lease development and production activities commence.

(1)(i) You must furnish the Regional Director a $500,000 bond that guarantees compliance with all the terms and conditions of the lease by the earliest of:

(A) The date you submit a proposed Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD) for approval;

(B) The date you submit a request for approval of the assignment of a lease on which a DPP or DOCD has been approved; or

(C) December 8, 1997, for any lease for which a DPP or DOCD has been approved.

(ii) The Regional Director may authorize you to submit the $500,000 lease development bond after you submit a DPP or DOCD, but before he/she approves the installation of a platform or the commencement of drilling activities under the DPP or DOCD.

(iii) You may satisfy the bond requirement of this paragraph by providing a new bond or by increasing the amount of your existing bond.

(2) The lessee need not submit and maintain a $500,000 lease development bond pursuant to paragraph (b)(1) of this section if the lessee furnishes and maintains an areawide bond in the sum of $3 million issued by a qualified surety and conditioned on compliance with all the terms and conditions of oil and gas and sulphur leases held by the

lessee on the OCS for the area in which the lease is situated.

(c) When a lessee can demonstrate to the satisfaction of the authorized officer that wells and platforms can be abandoned and removed and the drilling and platform sites cleared of obstructions for less than the amount of lease bond coverage required under paragraph (b)(1) of this section, the authorized officer may accept a lease surety bond in an amount less than the prescribed amount but not less than the amount of the cost for well abandonment, platform removal, and site clearance.

(d) The Regional Director may determine that additional security (*i.e.,* security above the amounts prescribed in §§ 556.52(a) and 556.53(a) and (b) of this part) is necessary to ensure compliance with the obligations under your lease and the regulations in this chapter.

(1) The Regional Director's determination will be based on his/her evaluation of your ability to carry out present and future financial obligations demonstrated by:

(i) Financial capacity substantially in excess of existing and anticipated lease and other obligations, as evidenced by audited financial statements (including auditor's certificate, balance sheet, and profit and loss sheet);

(ii) Projected financial strength significantly in excess of existing and future lease obligations based on the estimated value of your existing OCS lease production and proven reserves of future production;

(iii) Business stability based on 5 years of continuous operation and production of oil and gas or sulphur in the OCS or in the onshore oil and gas industry;

(iv) Reliability in meeting obligations based on:

(A) Credit rating(s); or

(B) Trade references, including names and addresses of other lessees, drilling contractors, and suppliers with whom you have dealt; and

(v) Record of compliance with laws, regulations, and lease terms.

(2) You may satisfy the Regional Director's demand for additional security by increasing the amount of your existing bond or by providing a supplemental bond or bonds.

(e) The Regional Director will determine the amount of supplemental bond required to guarantee compliance. The Regional Director will consider potential underpayment of royalty and cumulative obligations to abandon wells, remove platforms and facilities, and clear the seafloor of obstructions in the Regional Director's case-specific analysis.

(f) If your cumulative potential obligations and liabilities either increase or decrease, the Regional Director may adjust the amount of supplemental bond required.

(1) If the Regional Director proposes an adjustment, the Regional Director will:

(i) Notify you and the surety of any proposed adjustment to the amount of bond required; and

(ii) Give you an opportunity to submit written or oral comment on the adjustment.

(2) If you request a reduction of the amount of supplemental bond required, you must submit evidence to the Regional Director demonstrating that the projected amount of royalties due the Government and the estimated costs of lease abandonment and cleanup are less than the required bond amount. If the Regional Director finds that the evidence you submit is convincing, he/she may reduce the amount of supplemental bond required.

§ 556.54 General requirements for bonds.

(a) Any bond or other security that you, as lessee or operator, provide under this part must:

(1) Be payable upon demand to the Regional Director;

(2) Guarantee compliance with all of your obligations under the lease and regulations in this chapter; and

(3) Guarantee compliance with the obligations of all lessees, operating rights owners and operators on the lease.

(b) All bonds and pledges you furnish under this part must be on a form or in a form approved by the Associate Director for BOEM. Surety bonds must be issued by a surety that the Treasury certifies as an acceptable surety on Federal bonds and that is listed in the current Treasury Circular No. 570. You may obtain a copy of the current Treasury Circular No. 570 from the Surety Bond Branch, Financial Management Service, Department of the Treasury, East-West Highway, Hyattsville, MD 20782.

(c) You and a qualified surety must execute your bond. When either party is a corporation, an authorized official for the party must sign the bond and attest to it by an imprint of the corporate seal.

(d) Bonds must be noncancellable, except as provided in § 556.58 of this part. Bonds must continue in full force and effect even though an event occurs that could diminish, terminate, or cancel a surety obligation under State surety law.

(e) Lease bonds must be:

(1) A surety bond;

(2) Treasury securities as provided in § 556.52(f);

(3) Another form of security approved by the Regional Director; or

(4) A combination of these security methods.

(f) You may submit a bond to the Regional Director executed on a form approved under paragraph (b) of this section that you have reproduced or generated by use of a computer. If you do this, and if the document omits terms or conditions contained on the form approved by the Associate Director for BOEM the bond you submit will be deemed to contain the omitted terms and conditions.

§ 556.55 Lapse of bond.

(a) If your surety becomes bankrupt, insolvent, or has its charter or license suspended or revoked, any bond coverage from that surety terminates immediately. In that event, you must promptly provide a new bond in the amount required under §§ 556.52 and 556.53 of this part to the Regional Director and advise the Regional Director of the lapse in your previous bond.

(b) You must notify the Regional Director of any action filed alleging that you, your surety, or guarantor are insolvent or bankrupt. You must notify the Regional Director within 72 hours of learning of such an action. All bonds must require the surety to provide this information to you and directly to BOEM.

§ 556.56 Lease-specific abandonment accounts.

(a) The Regional Director may authorize you to establish a lease-specific abandonment account in a federally insured institution in lieu of the bond required under § 556.53(d). The account must provide that, except as provided in paragraph (a)(3) of this section, funds may not be withdrawn without the written approval of the Regional Director.

(1) Funds in a lease-specific abandonment account must be payable upon demand to BOEM and pledged to meet the lessee's obligations under 30 CFR 250.1703.

(2) You must fully fund the lease-specific abandonment account to cover all the costs of lease abandonment and site clearance 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 abandonment and clearance of a lease. The required obligation may be associated with oil and gas or sulphur production from a lease other than the lease bonded through the lease-specific abandonment account.

§ 556.57 Using a third-party guarantee instead of a bond.

(a) *When the Regional Director may accept a third-party guarantee.* The Regional Director may accept a third-party guarantee instead of an additional bond under § 556.53(d) if:

(1) The guarantee meets the criteria in paragraph (c) of this section;

(2) The guarantee includes the terms specified in paragraph (d) of this section;

(3) The guarantor's total outstanding and proposed guarantees do not exceed 25 percent of its unencumbered net worth in the United States; and

(4) The guarantor submits an indemnity agreement meeting the criteria in paragraph (e) of this section.

(b) *What to do if your guarantor becomes unqualified.* If, during the life of your third-party guarantee, your guarantor no longer meets the criteria of paragraphs (a)(3) and (c)(3) of this section, you must:

(1) Notify the Regional Director immediately; and

(2) Cease production until you comply with the bond coverage requirements of this subpart.

(c) *Criteria for acceptable guarantees.* If you propose to furnish a third party's guarantee, that guarantee must ensure compliance with all lessees' lease obligations, the obligations of all operating rights owners, and the obligations of all operators on the lease. The Regional Director will base acceptance of your third-party guarantee on the following criteria:

(1) The period of time that your third-party guarantor (guarantor) has been in continuous operation as a business entity where:

(i) Continuous operation is the time that your guarantor conducts business immediately before you post the guarantee; and

(ii) Continuous operation excludes periods of interruption in operations that are beyond your guarantor's control and that do not affect your guarantor's likelihood of remaining in business during exploration, development, production, abandonment, and clearance operations on your lease.

(2) Financial information available in the public record or submitted by your guarantor, on your guarantor's own initiative, in sufficient detail to show to the Regional Director's satisfaction that your guarantor is qualified based on:

(i) Your guarantor's current rating for its most recent bond issuance by either Moody's Investor Service or Standard and Poor's Corporation;

(ii) Your guarantor's net worth, taking into account liabilities under its guarantee of compliance with all the terms and conditions of your lease, the regulations in this chapter, and your guarantor's other guarantees;

(iii) Your guarantor's ratio of current assets to current liabilities, taking into account liabilities under its guarantee of compliance with all the terms and conditions of your lease and the regulations in this chapter and your guarantor's other guarantees; and

(iv) Your guarantor's unencumbered fixed assets in the United States.

(3) When the information required by paragraph (c) of this section is not publicly available, your guarantor may submit the information in the following table. Your guarantor must update the information annually within 90 days of the end of the fiscal year or by the date prescribed by the Regional Director.

The guarantor should submit . . .	That . . .
(i) Financial statements for the most recently completed fiscal year,	Include a report by an independent certified public accountant containing the accountant's audit opinion or review opinion of the statements. The report must be prepared in conformance with generally accepted accounting principles and contain no adverse opinion.
(ii) Financial statements for completed quarters in the current fiscal year,	Your guarantor's financial officer certifies to be correct.
(iii) Additional information as requested by the Regional Director,	Your guarantor's financial officer certifies to be correct.

(d) *Provisions required in all third-party guarantees.* Your third-party guarantee must contain each of the following provisions.

(1) If you, your operator, or an operating rights owner fails to comply with any lease term or regulation, your guarantor must either:

(i) Take corrective action; or

(ii) Be liable under the indemnity agreement to provide, within 7 calendar days, sufficient funds for the Regional Director to complete corrective action.

(2) If your guarantor complies with paragraph (d)(1) of this section, this compliance will not reduce its liability.

(3) If your guarantor wishes to terminate the period of liability under its guarantee, it must:

(i) Notify you and the Regional Director at least 90 days before the proposed termination date;

(ii) Obtain the Regional Director's approval for the termination of the period of liability for all or a specified portion of your guarantor's guarantee; and

(iii) Remain liable for all work and workmanship performed during the period that your guarantor's guarantee is in effect.

(4) You must provide a suitable replacement security instrument before

the termination of the period of liability under your third-party guarantee.

(e) *Required criteria for indemnity agreements.* If the Regional Director approves your third-party guarantee, the guarantor must submit an indemnity agreement.

(1) The indemnity agreement must be executed by your guarantor and all persons and parties bound by the agreement.

(2) The indemnity agreement must bind each person and party executing the agreement jointly and severally.

(3) When a person or party bound by the indemnity agreement is a corporate entity, two corporate officers who are authorized to bind the corporation must sign the indemnity agreement.

(4) Your guarantor and the other corporate entities bound by the indemnity agreement must provide the Regional Director copies of:

(i) The authorization of the signatory corporate officials to bind their respective corporations;

(ii) An affidavit certifying that the agreement is valid under all applicable laws; and

(iii) Each corporation's corporate authorization to execute the indemnity agreement.

(5) If your third-party guarantor or another party bound by the indemnity agreement is a partnership, joint venture, or syndicate, the indemnity agreement must:

(i) Bind each partner or party who has a beneficial interest in your guarantor; and

(ii) Provide that, upon demand by the Regional Director under your third-party guarantee, each partner is jointly and severally liable for compliance with all terms and conditions of your lease.

(6) When forfeiture is called for under § 556.59 of this part, the indemnity agreement must provide that your guarantor will either:

(i) Bring your lease into compliance; or

(ii) Provide, within 7 calendar days, sufficient funds to permit the Regional Director to complete corrective action.

(7) The indemnity agreement must contain a confession of judgment. It must provide that, if the Regional Director determines that you, your operator, or an operating rights owner is in default of the lease, the guarantor:

(i) Will not challenge the determination; and

(ii) Will remedy the default.

(8) Each indemnity agreement is deemed to contain all terms and conditions contained in this paragraph (e), even if the guarantor has omitted them.

§ 556.58 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 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 end of lease 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 § 556.52(a) or under § 556.53(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 supplemental bonds submitted under § 556.53(d), the surety issuing the new supplemental bond agrees to assume that portion of the outstanding liabilities that accrued during the period of liability which 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 § 556.52(a), § 556.53(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) Supplemental bonds submitted under § 556.53(d),	When the Regional Director determines that you have met all your obligations covered by the supplemental bond,	When you meet your bonded obligations, unless the Regional Director: (i) Determines that the future potential liability resulting from any undetected problems is greater than the amount of the base bond; and

For the following type of bond	The period of liability will end	Your bond will be cancelled . . .
		(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.

§ 556.59 Forfeiture of bonds and/or other securities.

This section explains how a bond or other security may be forfeited.

(a) The Regional Director will call for forfeiture of all or part of the bond, other form of security, or guarantee you provide under this part if:

(1) You (the party who provided the bond) refuse, or the Regional Director determines that you are unable, to comply with any term or condition of your lease; or

(2) You default under one of the conditions under which the Regional Director accepts your bond, third-party guarantee, and/or other form of security.

(b) The Regional Director may pursue forfeiture of your bond without first making demands for performance against any lessee, operating rights owner, or other person authorized to perform lease obligations.

(c) The Regional Director will:

(1) Notify you, the surety on your bond or other form of security, and any third-party guarantor, of his/her determination to call for forfeiture of the bond, security, or guarantee under this section.

(i) This notice will be in writing and will provide the reasons for the forfeiture and the amount to be forfeited.

(ii) The Regional Director must base the amount he/she determines is forfeited upon his/her estimate of the total cost of corrective action to bring your lease into compliance.

(2) Advise you, your third-party guarantor, and any surety, that you, your guarantor, and any surety may avoid forfeiture if, within 5 working days:

(i) You agree to, and demonstrate that you will, bring your lease into compliance within the timeframe that the Regional Director prescribes;

(ii) Your third-party guarantor agrees to, and demonstrates that it will, complete the corrective action to bring your lease into compliance within the timeframe that the Regional Director prescribes; or

(iii) Your surety agrees to, and demonstrates that it will, bring your lease into compliance within the timeframe that the Regional Director prescribes, even if the cost of compliance exceeds the face amount of the bond or other surety instrument.

(d) If the Regional Director finds you are in default, he/she may cause the forfeiture of any bonds and other security deposited as your guarantee of compliance with the terms and conditions of your lease and the regulations in this chapter.

(e) If the Regional Director determines that your bond and/or other security is forfeited, the Regional Director will:

(1) Collect the forfeited amount; and

(2) Use the funds collected to bring your leases into compliance and to correct any default.

(f) If the amount the Regional Director collects under your bond and other security is insufficient to pay the full cost of corrective actions he/she may:

(1) Take or direct action to obtain full compliance with your lease and the regulations in this chapter; and

(2) Recover from you, any co-lessee, operating rights owner, and/or any third-party guarantor responsible under this subpart all costs in excess of the amount he/she collects under your forfeited bond and other security.

(g) The amount that the Regional Director collects under your forfeited bond and other security may exceed the costs of taking the corrective actions required to obtain full compliance with the terms and conditions of your lease and the regulations in this chapter. In this case, the Regional Director will return the excess funds to the party from whom they were collected.

Subpart J—Assignments, Transfers, and Extensions

§ 556.62 Assignment of lease or interest in lease.

This section explains how to assign record title and other interests in OCS oil and gas or sulphur leases.

(a) BOEM may approve the assignment to you of the ownership of the record title to a lease or any undivided interest in a lease, or an officially designated subdivision of a lease, only if:

(1) You qualify to hold a lease under § 556.35(b);

(2) You provide the bond coverage required under subpart I of this part; and

(3) The Regional Director approves the assignment.

(b) An assignment shall be void if it is made pursuant to any prelease agreement described in § 556.44(c) of this part that would cause a bid to be disqualified.

(c) Any approved assignment shall be deemed to be effective on the first day of the lease month following its filing in the appropriate office of the BOEM, unless at the request of the parties, an earlier date is specified in the approval.

(d) You, as assignor, are liable for all obligations that accrue under your lease before the date that the Regional Director approves your request for assignment of the record title in the lease. The Regional Director's approval of the assignment does not relieve you of accrued lease obligations that your assignee, or a subsequent assignee, fails to perform.

(e) Your assignee and each subsequent assignee are liable for all obligations that accrue under the lease after the date that the Regional Director approves the governing assignment. They must:

(1) Comply with all the terms and conditions of the lease and all regulations issued under the Act; and

(2) Remedy all existing environmental problems on the tract, properly abandon all wells, and reclaim the lease site in accordance with 30 CFR part 250, subpart Q.

(f) If your assignee, or a subsequent assignee, fails to perform any obligation under the lease or the regulations in this chapter, the Regional Director may

require you to bring the lease into compliance to the extent that the obligation accrued before the Regional Director approved the assignment of your interest in the lease.

§ 556.63 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 FEE TABLE

Service	Fee amount	30 CFR citation
(1) Record Title/Operating Rights (Transfer)	$186	§ 556.64
(2) Non-required Document Filing	27	§ 556.64

(b) 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 with the amended application.

§ 556.64 How to file transfers.

This section explains how to file instruments with BOEM that create and/or transfer interests in OCS oil and gas or sulphur leases.

(a) You must submit to the Regional Director for approval all instruments that create or transfer ownership of a lease interest.

(1) You must submit two copies of the instruments that create or transfer an interest. Each instrument that creates or transfers an interest must describe by officially designated subdivision the interest you propose to create or transfer.

(2) You must submit your proposal to create or transfer an interest, or create or transfer separate operating rights, subleases, and record title interests within 90 days of the last date that a party executes the transfer agreement.

(3) The transferee must meet the citizenship and other qualification criteria specified in § 556.35 of this part. When you submit an instrument to create or transfer an interest as an association, you must include a statement signed by the transferee about the transferee's citizenship and qualifications to own a lease.

(4) Your instrument to create or transfer an interest must contain all of the terms and conditions to which you and the other parties agree.

(5) You do not gain a release of any nonmonetary obligation under your lease or the regulations in this chapter by creating a sublease or transferring operating rights.

(6) You do not gain a release from any accrued obligation under your lease or the regulations in this chapter by assigning your record title interest in the lease.

(7) You may create or transfer carried working interests, overriding royalty interests, or payments out of production without obtaining the Regional Director's approval. However, you must file instruments creating or transferring carried working interests, overriding royalty interests, or payments out of production with the Regional Director for record purposes.

(8) You must pay electronically through Pay.gov at: *https://www.pay.gov/paygov/* the service fee listed in § 556.63 of this subpart and you must include a copy of the *Pay.gov* confirmation receipt page with your application for approval of any instrument of transfer you are required to file (Record Title and/or Operating Rights (Transfer) Fee). Where multiple transfers of interest are included in a single instrument, a separate fee applies to each individual transfer of interest. 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* the service fee listed in § 556.63 (Non-required Document Filing Fee) 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, in behalf of the holder of a lease, operating rights or sublease, shall furnish evidence of authority to execute the assignment or application for approval and the statement required by § 556.46 of this part.

(c) When you request approval for an assignment that assigns all your record title interest in a lease or that creates a segregated lease, your assignee must furnish a bond in the amount prescribed in §§ 556.52 and 556.53 of this part.

(d) When you request approval for an assignment that assigns less than all the record title of a lease and that does not create a separate lease, the assignee may, with the surety's consent, become a joint principal on the surety instrument that guarantees compliance with all the terms and conditions of the lease.

(e) An heir or devisee of a deceased holder of a lease, or any interest therein, shall be recognized as the lawful successor to such lease or interest, if evidence of status as an heir or devisee is furnished in the form of:

(1) A certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or,

(2) If no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will.

(f) In addition to the requirements of paragraph (d) of this section, the heirs or devisees shall file statements that they are the persons named as successors to the estate with evidence of their qualifications as provided in § 556.46 of this part.

(g) In the event an heir or devisee is unable to qualify to hold the lease or interest, the heir or devisee shall be recognized as the lawful successor of the deceased and be entitled to hold the lease for a period of not to exceed 2 years from the date of death of the predecessor in interest.

(h) Your heirs, executors, administrators, successors, and assigns are bound to comply with each obligation under any lease and under the regulations in this chapter.

(1) You are jointly and severally liable for the performance of each nonmonetary obligation under the lease and under the regulations in this chapter with each prior lessee and with each operating rights owner holding an interest at the time the obligation accrued, unless this chapter provides otherwise.

(2) Sublessees and operating rights owners are jointly and severally liable for the performance of each nonmonetary obligation under the lease and under the regulations in this chapter to the extent that:

(i) The obligation relates to the area embraced by the sublease;

(ii) Those owners held their respective interest at the time the obligation accrued; and

(iii) This chapter does not provide otherwise.

(i) Where the proposed assignment or transfer is by a person who, at the time of acquisition of an interest in the lease, was on the List of Restricted Joint Bidders, and that assignment or transfer is of less than the entire interest of the assignor or transferor, to a person or persons on the same List of Restricted Joint Bidders, the assignor or transferor shall file a copy, prior to approval of the assignment, of all agreements applicable to the acquisition of that lease or a fractional interest.

§ 556.65 Attorney General review.

Prior to the approval of an assignment or transfer, the Secretary shall consult with and give due consideration to the views of the Attorney General. The Secretary may act on an assignment or transfer if the Attorney General has not responded to the request for consultation within 30 days of said request.

§ 556.67 Separate filings for assignments.

A separate instrument of assignment shall be filed for each lease. When transfers to the same person, association or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee shall be sufficient.

§ 556.68 Effect of assignment of a particular tract.

(a) When an assignment is made of all the record title to a portion of the acreage in a lease, the assigned and retained portions become segregated into separate and distinct leases. In such a case, the assignee becomes a lessee of the Government as to the segregated tract that is the subject of assignment, and is bound by the terms of the lease as though the lease had been obtained from the United States in the assignee's own name, and the assignment, after its approval, shall be the basis of a new record. Royalty, minimum royalty and rental provisions of the original lease shall apply separately to each segregated portion.

(b) For assignments of a portion of an oil and gas lease approved after the effective date of this section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas is produced from that segregated portion of the leased area in paying quantities or drilling or well reworking operations as approved by the Secretary are conducted.

(c) For those assignments approved prior to the effective date of this section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil and gas may be produced from the original leased area in paying quantities or drilling or well reworking operations, as approved by the Secretary, are conducted.

§ 556.70 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.

§ 556.71 Directional drilling.

In accordance with an approved exploration plan or development and production plan, a lease may be maintained in force by directional wells drilled under the leased area from surface locations on adjacent or adjoining land not covered by the lease. In such circumstances, drilling shall be considered to have commenced on the leased area when drilling is commenced on the adjacent or adjoining land for the purpose of directional drilling under the leased area through any directional well surfaced on adjacent or adjoining land. Production, 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.

§ 556.72 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.

Subpart K—Termination of Leases

§ 556.76 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivision thereof may be surrendered by the record title holder by filing a written relinquishment, in triplicate, with the appropriate OCS office of the BOEM. No filing fee is required. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and the surety to make all payments due, including any accrued rentals, royalties and deferred bonuses and to abandon all wells and condition or remove all platforms and other facilities on the land to be relinquished to the satisfaction of the Director.

§ 556.77 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 L—Section 6 Leases

§ 556.79 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.

§ 556.80 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the Act shall not preclude the issuance of other leases of the same area for deposits of other minerals. However, no other lease of minerals shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease. No sulphur leases shall be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the Act.

Subpart M—Studies

§ 556.82 Environmental studies.

(a) The Director shall conduct a study of any area or region included in any lease sale in order to establish information needed for assessment and management of impacts on the human, marine and coastal environments which may be affected by OCS oil and gas activities in such area or region. Any study shall, to the extent practicable, be designed to predict environmental impacts of pollutants introduced into the environments and of the impacts of offshore activities on the seabed and affected coastal areas.

(b) Studies shall be planned and carried out in cooperation with the affected States and interested parties and, to the extent possible, shall not duplicate studies done under other laws. Where appropriate, the Director shall, to the maximum extent practicable, enter into agreements with the National Oceanic and Atmospheric Administration in executing the environmental studies responsibilities. By agreement, the Director may also utilize services, personnel or facilities of any Federal, State or local government agency in the conduct of such study.

(c) Any study of an area or region required by paragraph (a) of this section for a lease sale shall be commenced not later than 6 months prior to holding a lease sale for that area. The Director may utilize information collected in any prior study. The Director may initiate studies for areas or regions not identified in the leasing program.

(d) After the leasing and developing of any area or region, the Director shall conduct such studies as are deemed necessary to establish additional information and shall monitor the human, marine and coastal environments of such area or region in a manner designed to provide information which can be compared with the results of studies conducted prior to OCS oil and gas development. This shall be done to identify any significant changes in the quality and productivity of such environments, to establish trends in the areas studies, and to design experiments identifying the causes of such changes. Findings from such studies shall be used to recommend modifications in practices which are employed to mitigate the effects of OCS activities and to enhance the data/information base for predicting impacts which might result from a single lease sale or cumulative OCS activities.

(e) Information available or collected by the studies program shall, to the extent practicable, be provided in a form and in a timeframe that can be used in the decision-making process associated with a specific leasing action or with longer term OCS minerals management responsibilities.

Subpart N—Bonus or Royalty Credits for Exchange of Certain Leases Offshore Florida

§ 556.90 Which leases may I exchange for a bonus or royalty credit?

You may exchange a lease for a bonus or royalty credit if it:

(a) Was in effect on December 20, 2006, and

(b) Is 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.

§ 556.91 How much bonus or royalty credit will BOEM grant in exchange for a lease?

The amount of the bonus or royalty credit for an exchanged lease equals the sum of:

(a) The amount of the bonus payment; and

(b) All rent paid for the lease as of the date the lessee submits the request to exchange the lease under § 556.92 to BOEM.

§ 556.92 What must I do to obtain a bonus or royalty credit?

(a) To obtain the bonus or royalty credit, all of the record title interest owners in the lease must submit the following to the BOEM Regional Supervisor for Leasing and Environment for the Gulf of Mexico on or before October 14, 2010.

(1) A written request to exchange the lease for the bonus or royalty credit, signed by all record title interest owners in the lease.

(2) The name and contact information for a person who will act as a contact for each record title interest owner.

(3) Documentation of each record title interest owner's percentage share in the lease.

(4) A list of all bonus and rental payments for that lease made by, or on behalf of, each of the current record title owners.

(5) A written relinquishment of the lease as described in § 556.76. Notwithstanding § 556.76, the relinquishment will become effective when the credit becomes effective under paragraph (b) of this section.

(b) The credit becomes effective when BOEM issues a certification to the record title interest owners that the lease has qualified for the credit and when ONRR issues the credit.

§ 556.93 How is the bonus or royalty credit allocated among multiple lease owners?

BOEM will allocate the bonus or royalty credit for an exchanged lease to the current record title interest owners in the same percentage share as each owner has in the lease as of the date of the request to exchange the lease.

§ 556.94 How may I use the bonus or royalty credit?

(a) You may use a credit issued under this part in lieu of a monetary payment due under any lease in the Gulf of Mexico not subject to the revenue distribution provisions of section 8(g)(2) of the OCSLA (43 U.S.C. 1337(g)(2)) for either:

(1) A bonus for acquisition of an interest in a new lease; or

(2) Royalty due on oil and gas production after October 14, 2008.

(b) You may not use a bonus or royalty credit in lieu of delivering oil or gas taken as royalty-in-kind.

(c) If you have any credit that remains unused after 5 years from the date ONRR issued the credit, ONRR reserves the right to apply the remaining credit to any of your obligations.

§ 556.95 How do I transfer a bonus or royalty credit to another person?

(a) You may transfer your bonus or royalty credit to any other person by

submitting to the BOEM Adjudication Unit for the Gulf of Mexico two originally executed transfer letters of agreement.

(b) Authorized officers indicated on the qualification card filed with BOEM of all companies involved in transferring and receiving the credit must sign the transfer letters of agreement.

(c) A transfer letter of agreement must include:

(1) The effective date of the transfer,

(2) The OCS–G number for the lease that originally qualified for the credit,

(3) The amount of the credit being transferred,

(4) Company names punctuated exactly as filed on the qualification card at BOEM, and

(5) A corporate seal, if you used a corporate seal in your initial qualification to hold OCS leases.

(d) The transferee of a credit transferred under this section may use it in accordance with § 556.94 as soon as BOEM sends a confirmation of the transfer to the transferee.

Appendix to Part 556—Oil and Gas Cash Bonus Bid

The following bid is submitted for an oil and gas lease on the area of the Outer Continental Shelf specified below:

Tract No.*	Total amount bid	Amount per acre (or per hectare)	Amount of cash submitted with bid

*Or, if tract numbers are not used, Protraction Diagram or Leasing Map and block number.

Bidder qualification No.	Proportionate interest of company(s) submitting bid	Name and address of bidding company
____ Misc. No.		

_____,

Authorized signatory's name and title.

PART 559—MINERAL LEASING: DEFINITIONS

Sec.

559.001 Purpose and scope.

559.002 Definitions.

Authority: Pub. L. 83–212, 67 Stat. 462, 43 U.S.C. 1331 *et seq.,* as amended by Pub. L. 95–372, 92 Stat. 629.

§ 559.001 Purpose and scope.

The purpose of this part 559 is to define various terms appearing in part 560.

§ 559.002 Definitions.

For purposes of part 560:

Area or *region* means the geographic area or region over which the BOEM designated official 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 any consideration, including, but not limited to, bonuses, rents or royalties conferred, and convenants to be observed, authorizes a person to explore for, or develop, or produce (or to do any or all of these) oil and gas, coal, oil shale, tar sands, and geothermal resources on lands or interests in lands under Federal jurisdiction.

Gas means natural gas as defined by the Federal Energy Regulatory Commission.

OCS means the Outer Continental Shelf, which includes all submerged lands (1) that lie seaward outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (Pub. L. 31–35, 67 Stat. 29, (43 U.S.C. 1301)) and (2) of which the subsoil and seabed appertain to the United States are subject to its jurisdiction and control.

OCSLA means the Outer Continental Shelf Lands Act, as amended (Act of August 7, 1953, Ch. 345, 67 Stat. 462, 43 U.S.C. 1331 *et seq.,* as amended by Pub. L. 95–372, 92 Stat. 629).

Oil means a mixture of hydrocarbons that exists in a liquid or gaseous phase in an underground reservoir and which remains or becomes liquid at atmospheric pressure after passing through surface separating facilities, including condensate recovered by means other than a manufacturing process.

PART 560—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

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Sec.

560.1 What is the purpose of this part?

560.2 What definitions apply to this part?

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Eligible Leases

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Royalty Suspensions (RS) Leases

560.120 How does royalty suspension apply to leases issued in a sale held after November 2000?

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560.123 How do I measure natural gas production for a lease issued in a sale held after November 2000?

560.124 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

560.130 What criteria does BOEM use for selecting bidding systems and bidding system components?

Subpart C—[Reserved]

Subpart D—Joint Bidding

560.301 What is the purpose of this subpart?
560.302 What definitions apply to this subpart?
560.303 What are the joint bidding requirements?

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

Subpart A—General Provisions

§ 560.1 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.

§ 560.2 What definitions apply to this part?

OCS lease means a Federal lease for oil and gas issued under the OCSLA.

OCSLA means the Outer Continental Shelf Lands Act, (43 U.S.C. 1331 *et seq.*), as amended.

Person includes, in addition to a natural person, an association, a State, or a private, public, or municipal corporation.

We means the Bureau of Ocean Energy Management (BOEM).

You means the lessee or operating rights holder.

§ 560.3 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 to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 381 Elden Street, Herndon, VA 20170.

Subpart B—Bidding Systems

General Provisions

§ 560.101 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.

§ 560.102 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.

§ 560.110 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**.

For the bidding system . . .	The bid variable is the . . .	And the characteristics are . . .
(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. (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**.

§ 560.111 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.

Eligible Leases

§ 560.112 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.

§ 560.113 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.

§ 560.114 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.

§ 560.115 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.

§ 560.116 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.

Royalty Suspension (RS) Leases

§ 560.120 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.

§ 560.121 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.

§ 560.122 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.

§ 560.123 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.

§ 560.124 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.

Bidding System Selection Criteria

§ 560.130 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—[Reserved]

Subpart D—Joint Bidding

§ 560.301 What is the purpose of this subpart?

The purpose of this subpart is to encourage participation in OCS oil and gas lease sales by limiting the requirement for filing ''Statements of Production'' to certain joint bidders.

§ 560.302 What definitions apply to this subpart?

For the purposes of this subpart, all terms used are defined as in 30 CFR 556.40.

§ 560.303 What are the joint bidding requirements?

(a) You must file a Statement of Production with the Director, according to the requirements of §§ 556.38 through 556.44 if:

(1) You submit a joint bid for any OCS oil and gas lease during a 6-month bidding period; and

(2) You were chargeable for the prior production period with an average daily production from all sources in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products.

(b) The Statement of Production that you file under paragraph (a) of this section must state that you are chargeable for the prior production period with an average daily production in excess of the quantities listed in paragraph (a) of this section.

(c) If your average daily production in the prior production period met or exceeded the quantities specified in paragraph (a) of this section, you may not submit a joint bid for any OCS oil and gas lease during the applicable 6-month bidding period with any other person similarly chargeable. We will disqualify and reject these bids.

(d) If your average daily production in the prior production period met or exceeded the quantities specified in paragraph (a) of this section, you may not enter into an agreement prior to a lease sale that would result in two or more persons, similarly chargeable, acquiring or holding any interest in the tract for which the bid is submitted. We will disqualify and reject these bids.

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.

§ 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?
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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

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Geophysical Data and Information

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Subpart E—Information Collection

580.80 Paperwork Reduction Act statement—information collection.

Authority: 31 U.S.C. 9701, 43 U.S.C. 1334.

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.
(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, 770 Paseo Camarillo, Camarillo, CA 93010.

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, 381 Elden Street, Herndon, VA 20170.

PART 581—LEASING OF MINERALS OTHER THAN OIL, GAS, AND SULPHUR IN THE OUTER CONTINENTAL SHELF

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Authority: 31 U.S.C. 9701, 43 U.S.C. 1334.

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 Associate Director for BOEM. 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.

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

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Authority: 43 U.S.C. 1334.

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) [Reserved];

(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 Associate Director for Offshore Energy and Minerals Management. A single copy of the required form is to be executed by the principal or, in the case of surety bonds, by both the principal and an acceptable surety.

(c) Only those surety bonds issued by qualified surety companies approved by the Department of the Treasury shall be accepted (see Department of Treasury Circular No. 570 and any supplemental or replacement circulars).

(d) Personal bonds shall be accompanied by a cashier's check, certified check, or negotiable U.S. Treasury bonds of an equal value to the amount specified in the bond. Negotiable Treasury bonds shall be accompanied by a proper conveyance of full authority to the Director to sell such securities in case of default in the performance of the terms and conditions of the lease.

(e) A bond in the minimum amount of $50,000 to cover the lessee's obligations under the lease shall be submitted prior to the commencement of any activity on a leasehold. A $50,000 bond shall not be required on a lease if the lessee already maintains or furnishes a $300,000 bond conditioned on compliance with the terms of leases for OCS minerals other than oil, gas, and sulphur held by the lessee on the OCS for the area in which the lease is located. A bond submitted pursuant to § 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.

§ 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 585—RENEWABLE ENERGY AND ALTERNATE USES OF EXISTING FACILITIES ON THE OUTER CONTINENTAL SHELF

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Authority: 43 U.S.C. 1331 *et seq.,* 43 U.S.C. 1337.

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 or the executive of any local government or 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.

§ 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	.....	.....	.....	.....

Requirements to qualify to hold leases or grants on the OCS:	Corp.	Ltd. Prtnsp.	Gen. Prtnsp.	LLC	Trust
(3) Evidence of authority of titled positions to bind corporation, certified by Secretary/Assistant Secretary over corporate seal, including the following: (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.	XX	.....	.....	.....	.....
(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: (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.	.....	XX	XX	XX	.....
(8) Statement from general partner, certified by Secretary/Assistant Secretary that: (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.	.....	XX	.....	.....	.....
(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: Associate Director, Bureau of Ocean Energy Management, MS–4001, 381 Elden Street, Herndon, VA 20170.

(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.

§ 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* refer to an applicant, lessee, the operator, a designated agent of the lessee(s) or designated operator, ROW grant holder, RUE grant holder, or Alternate Use RUE grant holder under this part, or the possessive of each, depending on the context.

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.

§ 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, 381 Elden Street, Herndon, VA 20170.

(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.

30 CFR 585 subpart, title, and/or BOEM Form (OMB Control No.)	Reasons for collecting information and how used
(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.

§ 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, 381 Elden Street, Room 3313, Herndon, Virginia, 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

§ 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 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 us to consult with or respond to findings include the Endangered Species Act (ESA), and the Magnuson-Stevens Fishery Conservation and Management Act (MSA).

§ 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 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.

§ 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). Under the noncompetitive process, the acquisition fee specified in § 585.502(a) must be submitted with the Site Assessment Plan (SAP) or General Activities Plan (GAP).

(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.

§ 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 6 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.

§ 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:

(1) We will publish a notice, in the **Federal Register**, of such determination; and

(2) You must submit within 60 days of the date of the notice to BOEM:

(i) For a commercial lease, a SAP, as described in §§ 585.605 through 585.613; or

(ii) For a limited lease, a GAP, as described in §§ 585.640 through 585.648.

(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 and associated plans.

(f) If we approve or approve with conditions your SAP or GAP, we 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 6 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.

§ 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(b) through (i).

§ 585.233 [Reserved]

§ 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 issued competitively will have a preliminary term of 6 months to submit: (i) a SAP; or (ii) a combined SAP and COP. The preliminary term begins on the effective date of the lease. A commercial lease issued noncompetitively does not have a preliminary term.	If we receive 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 5 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 applicable parties. A request for lease renewal must be submitted 2 years before the end of the operations term. If you submit a COP, your operations term begins on the date that we approve the COP. If you submit a SAP/COP, your operations term begins 5 years after the date we approve the SAP/COP, or when fabrication and installation commence, whichever is earlier.	.....	The lease renewal request must meet the requirements, as provided 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 applicable parties. The lease renewal term begins upon expiration of the original operations term.	.....	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 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.

§ 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 issued competitively has a preliminary term of 6 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) The operations term begins when BOEM approves your GAP and issues your lease. A limited lease issued noncompetitively does not have a preliminary term.	.....	You must submit and BOEM must approve your GAP before we will issue a lease. The GAP must meet the requirements of §§ 585.640 through 585.648.
(3) Each limited lease has an operations term of 5 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.

§ 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?

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.

§ 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:

(1) In consultation with you, establish the terms and conditions for the grant;

(2) Require you to submit a GAP, as described in §§ 585.640 through

585.648, within 60 days of the determination of no competitive interest; and

(3) Evaluate your request for a noncompetitive grant and GAP simultaneously.

(c) If we award your ROW grant or RUE grant competitively, you must submit and receive BOEM approval of your GAP, as provided in §§ 585.640 through 585.648.

§ 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?

If we approve or approve with conditions your GAP, we 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.

§ 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 [Reserved]

§ 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 [Reserved]

§ 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 6-months rent paid for the preliminary term of your lease, you must make credit card or automated clearing house payments through the *Pay.gov* Web site, and you must include one copy of the *Pay.gov* confirmation receipt page with your unsolicited request or signed lease instrument. You may access the *Pay.gov* Web site through links on the BOEM Offshore Web site at: *http://www.boem.gov/offshore* or directly through *Pay.gov* at: *https://www.pay.gov/paygov/.*

(b) For rent during the preliminary term, subsequent to the first 6-months rent, or the site assessment term; or operating fees during the operations term, you must make your payments as required in 30 CFR 1218.51 of this chapter.

(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.
(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.

§ 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, under the regulations at 30 CFR part 1218, the first 6-months rent, as provided in § 585.500, 45 days after we issue your lease.

(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.

§ 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, under the regulations at 30 CFR part 1218, the first 6-months rent when BOEM issues your limited lease, as provided in § 585.500.

(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.

§ 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 . . .
(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.	(2) BOEM determines that the potential liability resulting from any undetected noncompliance is not greater than the amount of the lease base bond. 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) ÷ (1/12+1/4)] = 1/4.

(2) State B's share = [(1/4) ÷ (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?

Your plan submission requirements depend on whether your lease or grant was issued competitively or noncompetitively under subpart B or subpart C of this part.

(a) If your lease or grant is issued competitively, you must submit your SAP or your GAP within 6 months of issuance.

(b) If you request that a lease or grant be issued noncompetitively, you must submit your SAP or your GAP within 60 days after the Director issues a determination that there is no competitive interest.

(c) 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.

(d) 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.

§ 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 [Reserved]

§ 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.
(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.

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; (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 must I submit with my SAP to assist BOEM in complying with NEPA and other relevant laws?

(a) You must submit with your SAP detailed information to assist BOEM in complying with NEPA and other relevant laws, as appropriate. For a noncompetitive commercial lease, 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.

(b) For competitively issued commercial leases, BOEM will have prepared a NEPA document and consistency determination for the lease sale and site assessment activities. However, if you submit a SAP that shows changes in impacts from those identified in the NEPA document or consistency determination prepared for the lease, BOEM may determine that your SAP is subject to a new NEPA/CZMA and other relevant Federal reviews. In that case, BOEM will notify you of the 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, seagrasses, and 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, and 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.

Type of information	Including
(9) Consistency Certification	As required by CZMA, as appropriate: (i) 15 CFR part 930, subpart D, for noncompetitive leases; (ii) 15 CFR part 930, subpart E, for competitive leases.
(10) Other resources, conditions, and activities	As identified by BOEM.

§ 585.612 How will my SAP be processed for Federal consistency under the Coastal Zone Management Act?

Your SAP will be processed based on how your commercial lease was issued:

If your commercial lease was issued . . .	Your SAP will be handled as follows:
(a) Competitively	BOEM will prepare a consistency determination that will cover the lease sale and site assessment activities. However, if you submit a SAP that shows changes in impacts from those identified in the lease sale consistency determination, you may be subject to a new consistency review. In that case, BOEM will notify you of the determination and we will forward to the State CZM agency 1 copy and 1 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 and BOEM prepares its NEPA compliance document.
(b) Noncompetitively	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 State's CZM agency and BOEM at the same time.

§ 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 through 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;

Information:	Report contents:	Including:
		(iv) Hydrates; or (v) Ice scour of seabed sediments.
(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.
(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.

Project information:	Including:
(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.
(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, and 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.

Type of information:	Including:
(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: (i) 15 CFR part 930, subpart D, for noncompetitive leases. (ii) 15 CFR part 930, subpart E, for competitive leases.
(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 subsection 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76 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) ''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).

(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.

§ 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) BOEM will forward one copy of your COP, consistency certification, and associated data and information under the CZMA to the State's CZM agency 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.

§ 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. For a ROW grant or RUE grant issued competitively, you must submit your GAP within 6 months of issuance.

§ 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 [Reserved]

§ 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.
(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.

Project information:	Including:
(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.
(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. Your GAP 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, including:

Type of information:	Including:
(a) Hazard information	Meteorology, oceanography, sediment transport, geology, and shallow geological or manmade hazards.
(b) Water quality	Turbidity and total suspended solids from construction.
(c) Biological resources	Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, plankton, seagrasses, and plant life.
(d) Threatened or endangered species	As required by the ESA (16 U.S.C. 1531 *et seq.*).
(e) 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, and calving grounds; barrier islands, beaches, dunes, and wetlands.
(f) Archaeological resources	As required by NHPA (16 U.S.C. 470 *et seq.*), as amended.

Type of information:	Including:
(g) 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.
(h) Coastal and marine uses	Military activities, vessel traffic, and energy and nonenergy mineral exploration or development.
(i) Consistency Certification	As required by CZMA: (1) 15 CFR part 930, subpart D, for noncompetitive leases; (2) 15 CFR part 930, subpart E, for competitive leases.
(j) Other resources, conditions, and activities	As required by BOEM.

§ 585.647 How will my GAP be processed for Federal consistency under the Coastal Zone Management Act?

Your GAP will be processed based on how your limited lease, ROW grant, or RUE grant was issued:

If your limited lease, ROW, or RUE grant was issued:	Your GAP will be processed as follows:
(a) Competitively,	BOEM will forward 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 and BOEM prepares its NEPA compliance document.
(b) Noncompetitively,	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 State's CZM agency and BOEM at the same time.

§ 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.
(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″ x 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″ x 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.

Required documents	Required contents	Other requirements
(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.

Required documents	Required contents	Other requirements
(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 [Reserved]

§ 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?
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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.;* 43 U.S.C. 1331

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 *Pay.gov* at: *https://www.pay.gov/paygov/,* 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.

§ 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]

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H.R. 771/P.L. 112–38
To designate the facility of the United States Postal Service located at 1081 Elbel Road in Schertz, Texas, as the ''Schertz Veterans Post Office''. (Oct. 12, 2011; 125 Stat. 399)

H.R. 1632/P.L. 112–39
To designate the facility of the United States Postal Service located at 5014 Gary Avenue in Lubbock, Texas, as the ''Sergeant Chris Davis Post Office''. (Oct. 12, 2011; 125 Stat. 400)

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