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Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control; Final Rule

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID: BSEE–2015–0002; 15XE1700DX EEEE500000 EX1SF0000.DAQ000]

RIN 1014–AA11

Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control

AGENCY: Bureau of Safety and Environmental Enforcement, Interior.

ACTION: Final rule.

SUMMARY: Bureau of Safety and Environmental Enforcement (BSEE) is finalizing new regulations to consolidate into one part the equipment and operational requirements that are found in various subparts of BSEE's regulations pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning. This final rule focuses on blowout preventer (BOP) and well-control requirements, including incorporation of industry standards and revision of existing regulations, and adopts reforms in the areas of well design, well control, casing, cementing, real-time well monitoring, and subsea containment. The final rule also addresses and implements multiple recommendations resulting from various investigations of the *Deepwater Horizon* incident. This final rule will also incorporate guidance from several Notices to Lessees and Operators (NTLs) and revise provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

DATES: This final rule becomes effective on July 28, 2016. Compliance with certain provisions of the final rule, however, will be deferred until the times specified in those provisions and as described in Part III of the preamble.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of July 28, 2016.

FOR FURTHER INFORMATION CONTACT: Kirk Malstrom, Regulations and Standards Branch, (202) 258–1518, or by email: *regs@bsee.gov.*

SUPPLEMENTARY INFORMATION:

List of Acronyms and References

ANSI American National Standards Institute
APA Administrative Procedure Act
APD Application for Permit to Drill
API American Petroleum Institute
APM Application for Permit to Modify
BAST Best Available and Safest Technologies
BAVO BSEE-Approved Verification Organization
BOP Blowout Preventer
BOEM Bureau of Ocean Energy Management
BSEE Bureau of Safety and Environmental Enforcement
BSR Blind Shear Ram
CFR Code of Federal Regulations
CVA Certified Verification Agent
DHS Department of Homeland Security
DOCD Development Operations Coordination Document
DOI Department of the Interior
DPP Development and Production Plan
DWOPs Deepwater Operations Plans
ECD Equivalent Circulating Density
EDS Emergency Disconnect Sequence
E.O. Executive Order
EOR End of Operations Report
EP Exploration Plan
F Fahrenheit
FOIA Freedom of Information Act
FPSs Floating Production Systems
FPSO Floating Production, Storage, and Offloading Unit
FSHR Free Standing Hybrid Risers
GOM Gulf of Mexico
GOMR Gulf of Mexico region
GPS Global Positioning Systems
HPHT High Pressure High Temperature
IC Information Collection
IEC International Electrotechnical Commission
ISO International Organization for Standardization
JIT Joint Investigation Team
LMRP Lower Marine Riser Package
LWC Loss of Well Control
MASP Maximum Anticipated Surface Pressure
MAWHP Maximum Anticipated Wellhead Pressure
MIA Mechanical Integrity Assessment
MMS Minerals Management Service
MODUs Mobile Offshore Drilling Units
NAE National Academy of Engineering
NAICS North American Industry Classification System
NARA National Archives and Records Administration
NAS National Academy of Sciences
National Commission National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling
NIST National Institute of Standards and Technology
NTLs Notices to Lessees and Operators
NTTAA National Technology Transfer and Advancement Act
OCS Outer Continental Shelf
OCSLA Outer Continental Shelf Lands Act
OEM Original Equipment Manufacturer
OFR Office of Federal Register
OIRA Office of Information and Regulatory Affairs
OMB Office of Management and Budget
PEs Professional Engineers
ppg Pounds per gallon
psi Pounds per square inch
QA/QC Quality Assurance/Quality Control
RCD Regional Containment Demonstration
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RIN Regulation Identifier Number
ROT Remotely Operated Tools
ROV Remotely-Operated Vehicle
RP Recommended Practice
RTM Real-Time Monitoring
SBA Small Business Administration
SBREFA Small Business Regulatory Enforcement Fairness Act of 1996
SCCE Source Control and Containment Equipment
Secretary Secretary of the Interior
SEM Subsea Electronic Module
SEMS Safety and Environmental Management Systems
SIMOPS Simultaneous Operations
Spec. Specification
TAR Technical Assessment and Research
TBT Agreement Technical Barriers to Trade Agreement
TIA Takings Implication Analysis
TLPs Tension Leg Platforms
TVD True Vertical Depth
USCG United States Coast Guard
VBR Variable Bore Ram
VSL Value of a Statistical Life
WAR Well Activity Report
WTO World Trade Organization

Executive Summary

Following the devastating impacts of the April 20, 2010, *Deepwater Horizon* incident on the Gulf of Mexico (GOM) and the surrounding states and local communities, multiple investigations were conducted to determine the causes of the incident and to make recommendations to reduce the likelihood of a similar incident in the future. The investigative groups included:

—Department of the Interior (DOI)/ Department of Homeland Security (DHS) Joint Investigation Team;
—National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling;
—Chief Counsel for the National Commission; and
—National Academy of Engineering.

Each investigation outlined several recommendations to improve offshore safety. BSEE evaluated the recommendations and acted on a number of them quickly to improve offshore operations, while BSEE's decision making with respect to other recommendations followed additional input from industry and other stakeholders.

In April 2015, BSEE proposed regulations to, among other things, incorporate industry standards and NTL guidance; consolidate into one part the existing equipment and operational requirements that are found in various parts of BSEE's regulations; to revise and improve existing requirements for well design and control, casing and cementing; and to add new requirements for real-time monitoring

(RTM) and subsea containment. The proposed regulations also addressed many of the recommendations made by the previously listed investigative bodies, which found a need to incorporate well-control best practices to advance safety and protection of the environment. BSEE received over 176 public comments on the proposed rule, and considered those comments in developing these final regulations.

The requirements in this final rule, including the revisions made to the proposed regulations, reflect BSEE's consideration of the comments and BSEE's commitment to address the recommendations made in the *Deepwater Horizon* reports. This final rulemaking:

(1) Incorporates all or designated portions of the following industry standards:

—American Petroleum Institute (API) Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012;
—API Recommended Practice (RP) 2RD—Design of Risers for Floating Production Systems and Tension-Leg Platforms, First Edition, June 1998; Reaffirmed May 2006, Errata June 2009;
—API Specification (Spec.) Q1—Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Eighth Edition, December 2007, Effective Date: June 15, 2008;
—American National Standards Institute (ANSI)/API Specification (Spec.) 11D1, Packers and Bridge Plugs Second Edition, Effective Date: January 1, 2010;
—API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed: January 2009;
—ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005;
—ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004;
—API Spec. 16C, Specification for Choke and Kill Systems First Edition, January 1993;
—API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004; and
—ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011.

(2) Revises the requirements for Deepwater Operations Plans (DWOPs), which are required to be submitted to BSEE under specific circumstances, to add requirements on free standing hybrid risers (FSHR) for use with floating production, storage, and offloading units (FPSO).

(3) Revises 30 CFR part 250, subpart D, *Oil and Gas Drilling Operations,* to include requirements for:

—Safe drilling margins;
—Wellhead descriptions;
—Casing or liner centralization during cementing; and
—Source control and containment.

(4) Revises subparts E, *Oil and Gas Well-Completion Operations,* and F, *Oil and Gas Well-Workover Operations,* to include requirements for:

—Packer and bridge plug design; and
—Production packer setting depth.

(5) Revises Subpart Q, *Decommissioning Activities,* to include requirements for:

—Packer and bridge plug design;
—Casing bridge plugs; and
—Decommissioning applications and reports.

(6) Adds new subpart G, *Well Operations and Equipment,* and moves existing requirements that were duplicated in subparts D, E, F, and Q into new subpart G including:

—Rig and equipment movement reports;
—RTM; and
—Revised BOP requirements; including:
—Design and manufacture/quality assurance;
—Accumulator system capabilities and calculations;
—BOP and remotely operated vehicle (ROV) capabilities;
—BOP functions (*e.g.*, shearing);
—Improved and consistent testing frequencies;
—Maintenance;
—Inspections;
—Failure reporting;
—Third-party verification; and
—Additional submittals to BSEE, including up-to-date schematics.

(7) Incorporates the guidance from several NTLs into subpart G for:

—Global Positioning Systems (GPS) for Mobile Offshore Drilling Units (MODUs);
—Ocean Current Monitoring;
—Using Alternate Compliance in Safety Systems for Subsea Production Operations;
—Standard Reporting Period for the Well Activity Report (WAR); and
—Information to include in the WARs and End of Operations Reports (EOR).

Based on BSEE's economic analysis of available data, this final rule will be cost-beneficial. The estimated overall cost of the rule (outside those costs that are part of the economic baseline) over 10 years will be exceeded by the time-savings benefits to the industry resulting from the revisions to the former requirements for BOP pressure testing frequency for workovers and decommissionings. In addition, the final rule will also produce benefits to society, both quantifiable and unquantifiable, by reducing the probability of well control incidents involving oil spills.

Table of Contents

Paperwork Reduction Act (PRA) of 1995
National Environmental Policy Act of 1969 (NEPA)
Data Quality Act
Effects on the Nation's Energy Supply (E.O. 13211)

I. Background

A. BSEE

BSEE was established on October 1, 2011, as part of a major restructuring of DOI's offshore oil and gas regulatory programs to improve the management and oversight of, and accountability for, activities on the Outer Continental Shelf (OCS). The Secretary of the Interior (Secretary) announced the division of responsibilities of the former Minerals Management Service (MMS) among two new bureaus and one office within DOI in Secretarial Order No. 3299, issued on May 19, 2010. BSEE, one of the two new bureaus, assumed responsibility for ''safety and environmental enforcement functions including, but not limited to, the authority to permit activities, inspect, investigate, summon witnesses and [require production of] evidence[;] levy penalties; cancel or suspend activities; and oversee safety, response and removal preparedness.'' (See 76 FR 64431, October 18, 2011).

B. BSEE Statutory and Regulatory Authority and Responsibilities

BSEE derives its authority primarily from the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331–1356a. Congress enacted OCSLA in 1953, authorizing the Secretary of Interior to lease the OCS for mineral development, and to regulate oil and gas exploration, development, and production operations on the OCS. The Secretary has delegated authority to perform certain of these functions to BSEE.

To carry out its responsibilities, BSEE regulates offshore oil and gas operations to enhance the safety of offshore exploration and development of oil and gas on the OCS and to ensure that those operations protect the environment and implement advancements in technology. BSEE also conducts onsite inspections to assure compliance with regulations, lease terms, and approved plans. Detailed information concerning BSEE's regulations and guidance to the offshore oil and gas industry may be found on BSEE's website at: *http://www.bsee.gov/Regulations-and-Guidance/index.*

BSEE's regulatory program covers a wide range of facilities and activities, including drilling, completion, workover, production, pipeline, and decommissioning operations. Drilling, completion, workover, and decommissioning operations are types of well operations that offshore operators [1] perform throughout the OCS. These well operations are the primary focus of this rulemaking.

C. Purpose and Summary of the Rulemaking

A primary purpose of this rulemaking is to prevent future well-control incidents, including major incidents like the 2010 *Deepwater Horizon* catastrophe. In addition to the loss of 11 lives, that single event resulted in the release of 134 million gallons of oil, which spread over 43,300 square miles of the GOM and 1,300 miles of shoreline in several states. The environmental and other damages caused by the *Deepwater Horizon* incident were immense and have had long-lasting and widespread impacts on the Gulf and the affected states. For example, as part of a settlement agreement between BP and Federal and state governments, BP has agreed to pay over $8 billion for natural resources damages caused by the spill and for the restoration of natural resources in the Gulf of Mexico region (GOMR).[2] Those damages include severe adverse effects on wildlife, wetlands and other wildlife habitat, recreation and tourism, and commercial fishing. The *Deepwater Horizon* Natural Resource Damage Assessment (NRDA) Trustees have determined that ''the ecological scope of impacts from the *Deepwater Horizon* incident was unprecedented, with injuries affecting a wide array of linked resources across the northern Gulf ecosystem.'' The released oil ''was toxic to a wide range of organisms, including fish, invertebrates, plankton, birds, turtles, and mammals . . . [and] caused a wide array of toxic effects, including death, disease, reduced growth, impaired reproduction, and physiological impairments that made it more difficult for organisms to survive and reproduce.'' [3] In addition, state and local government economic damage claims arising from the *Deepwater Horizon* incident were significant and have been settled for another $5.9 billion.[4]

In addition, despite new regulations and improvements in industry standards and practices since the *Deepwater Horizon* incident, which have resulted in progress in certain areas of safety and environmental protection, loss of well control (LWC) incidents are happening at about the same rate five years after that incident as they were before. In 2013 and 2014, there were 8 and 7 LWC incidents per year, respectively—a rate on par with pre-*Deepwater Horizon* LWCs.[5] Some of these LWC incidents have resulted in blowouts, such as the 2013 Walter Oil and Gas incident that resulted in an explosion and fire on the rig. All 44 workers were safely evacuated, but the fire lasted over 72 hours and the rig was completely destroyed, resulting in a financial loss approaching $60 million. This incident occurred in part due to the crew's inability to identify critical well control indicators and to the failure of critical well control equipment.[6] Blowouts such as these can lead to much larger incidents that pose a significant risk to human life and can cause serious environmental damage.

Ensuring the integrity of the wellbore and maintaining control over the pressure and fluids during well operations are critical aspects of protecting worker safety and the environment. The investigations that followed the *Deepwater Horizon* incident, in particular, documented gaps or deficiencies in the OCS regulatory programs and made numerous recommendations for improvements. Accordingly, on April 17, 2015, BSEE proposed to consolidate its existing well-control rules into one subpart of the regulations, and to adopt new and revised regulatory requirements that address many of those recommendations, including those related to BOP system design, performance, and reliability. (*See* 80 FR 21504.)

[1] BSEE's regulations at 30 CFR part 20 generally apply to ''a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s) . . .'' covered by the definition of ''you'' in § 250.105. For convenience, this preamble will refer to all of the regulated entities as ''operators'' unless otherwise indicated.

[2] A summary and details of the recently approved natural resources damages settlement between BP and Federal and state governments are available at *www.doi.gov/deepwaterhorizon* and at *http://www.justice.gov/enrd/deepwater-horizon.*

[3] *Deepwater Horizon* NRDA Trustees, Final Programmatic Damage Assessment and Restoration Plan and Final Programmatic Environmental Impact Statement, at p. 1–14–1–15. On March 22, 2016, the NRDA Trustees issued a Record of Decision setting forth the basis for the Trustees' decision to select the comprehensive, integrated ecosystem restoration alternative (described in Final PDARP/PEIS Sections 5.5 and 5.10). More details regarding the findings of the Federal and state *Deepwater Horizon* NRDA Trustees as to natural resources impacts from the *Deepwater Horizon* incident may be found at: *http://www.gulfspillrestoration.noaa.gov/restoration-planning/gulf-plan/.*

[4] *https://www.justice.gov/enrd/deepwater-horizon.*

[5] *See http://www.bsee.gov/uploadedFiles/BSEE/BSEE_Newsroom/Publications_Library/Annual_Report/BSEE%202014%20Annual%20Report.pdf.*

[6] *See* BSEE, DOI, *Investigation of Loss of Well Control and Fire South Timbalier Area Block 220, Well. No. A–3 OCS–G24980—23 July 2013* (July 2015), at *http://www.bsee.gov/uploadedFiles/BSEE/Enforcement/Accidents_and_Incidents/Panel_Investigation_Reports/ST%20220%20Panel%20Report9_8_2015.pdf.*

Because BOP equipment and systems are critical components of many well operations, BSEE recognized that it was important to collect the best ideas on the prevention of well-control incidents and blowouts to assist in the development of the proposed rule. This included the knowledge, skillset, and experience possessed by the offshore oil and gas industry. Accordingly, BSEE participated in meetings, training, and workshops with industry, standards setting organizations, and other stakeholders in developing the proposed rule. (*See* 80 FR 21508–21509.)

The proposed rule discussed in detail topics such as:

- Implementing many of the recommendations related to well-control equipment.
- Increasing the performance and reliability of well-control equipment, especially BOPs.
- Improving regulatory oversight over the design, fabrication, maintenance, inspection, and repair of critical equipment.
- Gaining information on leading and lagging indicators of BOP component failures, identifying trends in those failures, and using that information to help prevent incidents.
- Ensuring that the industry uses recognized engineering practices, as well as innovative technology and techniques to increase overall safety.

To help ensure the development of effective regulations, the proposed rule used a hybrid regulatory approach incorporating prescriptive requirements, where necessary, as well as many performance-based requirements. BSEE recognizes the advantages and disadvantages of both approaches and understands that each approach could be effective and appropriate for specific circumstances.

A full discussion of these topics, along with other background and regulatory history, is contained in the notice of proposed rulemaking (*see* 80 FR 21504), which may be found on BSEE's website at *http://www.bsee.gov/Regulations-and-Guidance/Regulations-In-Development/,* and in the public docket for this rulemaking at: *http://www.regulations.gov* (in the Search box, enter BSEE–2015–0002, then click ''search'').

D. Availability of Incorporated Documents for Public Viewing

BSEE frequently uses standards (*e.g.,* codes, specifications, RPs) developed through a consensus process, facilitated by standards development organizations and with input from the oil and gas industry, as a means of establishing requirements for activities on the OCS. BSEE may incorporate these standards into its regulations without republishing the standards in their entirety in the Code of Federal Regulations (CFR), a practice known as incorporation by reference. The legal effect of incorporation by reference is that the incorporated standards become regulatory requirements. This incorporated material, like any other properly issued regulation, has the force and effect of law, and BSEE holds operators, lessees and other regulated parties accountable for complying with the documents incorporated by reference in our regulations. We currently incorporate by reference over 100 consensus standards in BSEE's regulations governing offshore oil and gas operations (*see* 30 CFR 250.198).

Federal regulations, at 1 CFR part 51, govern how BSEE and other Federal agencies incorporate various documents by reference. Agencies may only incorporate a document by reference by publishing in the **Federal Register** the document title, edition, date, author, publisher, identification number, and other specified information. The Director of the Federal Register must approve each publication incorporated by reference in a final rule. Incorporation by reference of a document or publication is limited to the specific edition cited by the agency in the final rule and approved by the Director of the Federal Register.

BSEE incorporates by reference in its regulations many oil and gas industry standards in order to require compliance with those standards in offshore operations. When a copyrighted publication is incorporated by reference into BSEE regulations, BSEE is obligated to observe and protect that copyright. BSEE provides members of the public with website addresses where these standards may be accessed for viewing—sometimes for free and sometimes for a fee. Standards development organizations decide whether to charge a fee. One such organization, API, provides free online public access to review its key industry standards, including a broad range of technical standards. These standards represent almost one-third of all API standards and include all that are safety-related or are incorporated into Federal regulations. Several of those standards are incorporated by reference in this final rule. In addition to the free online availability of these standards for viewing on API's website, hardcopies and printable versions are available for purchase from API. The API website address is: *http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents.*[7]

For the convenience of members of the viewing public who may not wish to purchase or view these incorporated documents online, they may be inspected at BSEE's offices, 45600 Woodland Road, Sterling, Virginia 20166; phone: 703–787–1665; 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/cfr/ibr-locations.html.*

E. Summary of Documents Incorporated by Reference

This rulemaking is substantive in terms of the content that is explicitly stated in the rule text itself, and it also incorporates by reference certain technical standards and specifications concerning BOPs and well control. A brief summary of each standard or specification follows.

API Standard 53—Blowout Prevention Equipment Systems for Drilling Wells

This standard provides requirements for the installation and testing of blowout prevention equipment systems whose primary functions are to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled volumes to be removed from the wellbore. BOP equipment systems are comprised of a combination of various components that are covered by this document. Equipment arrangements are also addressed. The components covered include: BOPs including installations for surface and subsea BOPs; choke and kill lines; choke manifolds; control systems; and auxiliary equipment.

This standard also provides new industry best practices related to the use of dual shear rams, maintenance and testing requirements, and failure reporting.

Diverters, shut-in devices, and rotating head systems (rotating control devices) whose primary purpose is to safely divert or direct flow rather than to confine fluids to the wellbore are not addressed. Procedures and techniques for well control and extreme temperature operations are also not included in this standard.

[7] To review these standards online, go to the API publications website at: *http://publications.api.org.* You must then log-in or create a new account, accept API's ''Terms and Conditions,'' click on the ''Browse Documents'' button, and then select the applicable category (*e.g.,* ''Exploration and Production'') for the standard(s) you wish to review.

API RP 2RD—Design of Risers for Floating Production Systems and Tension-Leg Platforms

This standard addresses structural analysis procedures, design guidelines, component selection criteria, and typical designs for all new riser systems used on Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs). The presence of riser systems within an FPS has a direct and often significant effect on the design of all other major equipment subsystems. This RP includes recommendations on: (1) Configurations and components; (2) general design considerations based on environmental and functional requirements; and (3) materials considerations in riser design.

API Spec. Q1—Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry

This specification establishes the minimum quality management system requirements for organizations that manufacture products or provide manufacturing-related processes under a product specification for use in the petroleum and natural gas industry. This standard requires that equipment be fabricated under a quality management system that provides for continual improvement, emphasizing defect prevention and the reduction of variation and waste in the supply chain and from service providers. The goal of this specification is to increase equipment reliability through better manufacturing controls.

API Spec. 6A—Specification for Wellhead and Christmas Tree Equipment

This specification defines minimal requirements for the design of valves, wellheads and Christmas tree equipment that is used during drilling and production operations. This specification includes requirements related to dimensional and functional interchangeability, design, materials, testing, inspection, welding, marking, handling, storing, shipment, purchasing, repair and remanufacture.

ANSI/API Spec. 11D1—Packers and Bridge Plugs

This specification provides minimum requirements and guidelines for packers and bridge plugs used downhole in oil and gas operations. The performance of this equipment is often critical to maintaining control of a well during drilling or production operations. This specification provides requirements for the functional specification and technical specification, including design, design verification and validation, materials, documentation and data control, repair, shipment, and storage.

ANSI/API Spec. 16A—Specification for Drill-through Equipment

This specification defines requirements for performance, design, materials, testing and inspection, welding, marking, handling, storing and shipping of BOPs and drill-through equipment used for drilling for oil and gas. It also defines service conditions in terms of pressure, temperature and wellbore fluids for which the equipment will be designed. This standard is applicable to, and establishes requirements for, the following specific equipment: Ram BOPs; ram blocks, packers and top seals; annular BOPs; annular packing units; hydraulic connectors; drilling spools; adapters; loose connections; and clamps. Conformance to this standard is necessary to ensure that this critical safety equipment has been designed and fabricated in a manner that ensures reliable performance.

API Spec. 16C—Specification for Choke and Kill Systems

This specification was formulated to provide for safe and functionally interchangeable surface and subsea choke and kill systems equipment utilized for drilling oil and gas wells. This equipment is used during emergencies to circulate out a ''kick'' and, therefore, the design and fabrication of the components is extremely important. This document provides the minimum requirements for performance, design, materials, welding, testing, inspection, storing and shipping. Equipment specific to and covered by this specification includes: Actuated valve control lines; articulated choke and kill lines; drilling choke actuators; drilling choke control lines, exclusive of BOP control lines; subsurface safety valve control lines; drilling choke controls; drilling chokes; flexible choke and kill lines; union connections; rigid choke and kill lines; and swivel unions.

API Spec. 16D—Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

This specification establishes design standards for systems that are used to control BOPs and associated valves that control well pressure during drilling operations. Although diverters are not considered well-control devices, their controls are often incorporated as part of the BOP control system. Thus, control systems for diverter equipment are included in the specification. Control systems for drilling well-control equipment typically employ stored energy in the form of pressurized hydraulic fluid (power fluid) to operate (open and close) the BOP stack components. For deepwater operations, subsea transmission of electric/optical (rather than hydraulic) signals may be used to shorten response times. The failure of these controls to perform as designed can result in a major well-control event. As a result, conformance to this specification is critical to ensuring that the BOPs and related equipment will operate in an emergency.

ANSI/API Spec. 17D—Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment

This standard provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads, and both vertical and horizontal subsea trees. These devices are located on the seafloor, and, therefore, ensuring the safe and reliable performance of this equipment is extremely important. This document specifies the associated tooling necessary to handle, test and install the equipment. It also specifies the areas of design, material, welding, quality control (including factory acceptance testing), marking, storing and shipping for both individual sub-assemblies (used to build complete subsea tree assemblies) and complete subsea tree assemblies.

API RP 17H—Remotely Operated Tools and Interfaces on Subsea Production Systems

This RP provides general recommendations and overall guidance for the design and operation of remotely operated tools (ROT) comprising ROT and ROV tooling used on offshore subsea systems. ROT and ROV performance is critical to ensuring safe and reliable deepwater operations and this document provides general performance guidelines for the equipment.

II. Organization of Subpart G

BSEE's former regulations repeated similar BOP requirements in multiple locations throughout 30 CFR part 250. In this final rule, BSEE is consolidating these requirements into subpart G (which previously had been reserved). The final rule will structure subpart G—Well Operations and Equipment, under the following undesignated headings:

—GENERAL REQUIREMENTS

—RIG REQUIREMENTS
—WELL OPERATIONS
—BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS
—RECORDS AND REPORTING

The sections contained within this new subpart will apply to all drilling, completion, workover, and decommissioning activities on the OCS, unless explicitly stated otherwise.

III. Discussion of Compliance Dates for the Final Rule

BSEE understands that operators may need time to comply with certain new requirements in this final rule. Based on information provided by industry, drilling rigs are now being built, or were built, pursuant to the same industry standards BSEE is now incorporating by reference (including API Standard 53), and many have already been retrofitted to comply with these industry standards. Furthermore, most drilling rigs already comply with recognized engineering practices and original equipment manufacturer (OEM) requirements related to repair and training.

BSEE has considered the public comments on the proposed compliance dates, as well as relevant information gained during, among other activities, BSEE's interactions with stakeholders, involvement in development of industry standards, and evaluation of current technology. Accordingly, BSEE is setting an effective date of 90 days following publication of the final rule, by which time operators will be required to demonstrate compliance with most of the final rule's provisions. BSEE has determined, however, that it is appropriate to extend the compliance dates for the following new requirements. Detailed explanations for these extended compliance dates are provided in parts V and VI of this document.

—As required in § 250.734(a)(15), operators must install a gas bleed line with two valves for the annular preventer no later than 2 years from publication of the final rule. BSEE is extending the timeframe for this requirement based on the current level of availability of the required equipment and the time needed to install the equipment. This timeframe was selected to avoid any rig downtime.
—As required by §§ 250.733(a)(1) and 250.734(a)(1), operators must have the capability to shear and seal tubing with exterior control lines no later than 2 years from the publication of the final rule. BSEE is aware that some current technology is available to shear tubing with exterior control lines; however, the effective date has been extended to allow operators to acquire and install (and, if necessary, to develop new or alternative) equipment to meet the requirements.
—As required by §§ 250.731, 250.732, 250.734, 250.738, and 250.739, operators must begin using a BSEE-approved verification organization (BAVO) for certain submittals, certifications, and verifications.[8] BSEE will develop and make available on its public website a list of BAVOs, consisting of qualified third-party organizations that BSEE determines are capable of performing the functions specified in this final rule, and that will help BSEE ensure that BOP systems are designed and maintained during their service life to minimize risk. Industry currently uses independent third-parties to perform verifications similar to the certifications and verifications that a BAVO will be required to perform under this final rule. BSEE is extending the compliance date for the use of BAVOs to no later than 1 year from the date when BSEE publishes the list of BAVOs. BSEE anticipates that most of the independent third-parties currently used by industry under the former regulations will become BAVOs, significantly facilitating compliance with the requirements to use BAVOs within the one-year timeframe.

In the interim, however, final § 250.732(a) requires that operators use independent third-parties to perform the certifications, verifications and reports that BAVOs must perform no later than 1 year after BSEE publishes a BAVO list. This transitional measure is necessary to ensure that there is no diminution of the safety and environmental protection currently afforded by the use of independent third-parties under the existing regulations or of the safety and environmental improvements anticipated under the new BAVO requirements, during the time required for BSEE to identify and for operators to use the BAVOs.

—As required in § 250.724, operators must comply with the RTM requirements no later than 3 years from the publication of the final rule.
—As required in § 250.734(a)(3), operators are required to have dedicated subsea accumulator capacity for autoshear and deadman functions on subsea BOPs within 5 years from the publication of the final rule. As explained in more detail in part VI.C, changing the compliance date for these new accumulator requirements—from the proposed 3 months to the final 5 years from the date of publication—will allow sufficient lead time for industry to acquire and install additional accumulator equipment as necessary and will correspond with the timeframe for compliance with the final dual shear ram requirements, which is when the additional accumulator capacity will most likely be needed.
—As required in § 250.734(a)(1), operators must install dual shear rams on subsea BOPs no later than 5 years from the publication of the final rule.
—As required in § 250.733(b)(1), surface BOPs installed on floating facilities 3 years after publication of the final rule must comply with the BOP requirements of § 250.734(a)(1).
—As required in § 250.734(a)(16), operators must install shear rams that center drill pipe during shearing operations no later than 7 years from the publication of the final rule.
—As required in § 250.735(g), operators must install remotely-controlled locks on surface BOP sealing rams no later than 3 years from publication of the final rule.
—As required in § 250.733(b)(2), for any risers installed 90 days after the date of the publication of the final rule or later, operators must use dual bore risers for surface BOPs on floating production facilities. The final rule does not require that operators change the riser configuration for risers that were installed on floating facilities before 90 days after the publication date of the final rule.
—As required in §§ 250.732(b)(1)(i) and 250.734(a)(1)(ii), the BOP must be able to shear electric-, wire-, and slick-line no later than 2 years after publication of the final rule.

IV. Issues Not Considered in This Rulemaking

BSEE is continuing to review and evaluate additional operational and equipment issues that are not included in this final rulemaking, such as:

—Well-control planning, procedures, training, and certification;
—Major rig equipment;
—Certification requirements for personnel servicing critical equipment;
—Choke and kill systems;
—Mud gas separators;
—Wellbore fluid safety practices, testing, and monitoring;

[8] For example, § 250.731(c)(2) requires certification and verifacation that all BOPs are designed and tested to maximun anticipated condictions.

—Diverter systems with subsea BOPs; and
—Additional severing requirements.

V. Discussion of Final Rule Requirements

Part V.A, which follows, summarizes and highlights some important requirements of the final rule that were described in more detail in the proposed rule. Some of these provisions received no comments during the public comment period, while other provisions were supported or criticized by certain commenters. Part V.B addresses significant relevant comments on certain proposed provisions and summarizes changes to those provisions that BSEE has made in the final rule based on consideration of those comments. Part V.C summarizes other changes to the proposed rule that BSEE has made in the final rule to avoid ambiguity or confusion, eliminate redundancies, correct minor drafting errors, or otherwise clarify the meaning of the new requirements.

A. Summary of Key Regulatory Provisions

After review of all the relevant public comments received on the proposed rule, BSEE determined that the following proposed revisions will be included in this final rule. Most of the proposed provisions are included without change, while several of the proposed provisions have been revised in the final rule in response to comments, as explained in parts V.B and VI of this document.

Shearing Requirements—

- Requires BOP shearing performance testing and results reporting to a BAVO. This will ensure that shearing capability for existing equipment complies with BSEE requirements.
- Requires compliance with the latest industry standards contained in API Standard 53.
- Requires that operators use two shear rams in subsea BOP stacks.
- Requires the use of BOP technology that provides for better shearing performance through the centering of the drill pipe in the shear rams.

Equipment Reliability and Performance—

- Requires compliance with industry standards, such as relevant provisions of API Standard 53, ANSI/API Spec. 6A, ANSI/API Spec. 16A, API Spec. 16C, API Spec. 16D, ANSI/API Spec. 17D, and API Spec. Q1. BOP operability will be improved by establishing minimum design, manufacture, and performance baselines that are essential to ensure the reliability and performance of this equipment.
- Requires inspection, maintenance, and repair of BOP-related equipment by appropriately trained personnel; this will also increase the reliability of BOP-related equipment.

Equipment Failure Reporting/Near-Miss Reporting—

- Requires that operators share information with Original Equipment Manufacturers (OEMs) related to the performance of their BOP system equipment. This sharing of information makes it possible for the OEMs to notify all users of any safety issues that arise with BOP system equipment.
- Requires that operators report any significant problems with BOP or well-control equipment to BSEE, so BSEE can determine whether information should be provided, in a timely manner, to OCS operators and, if appropriate, to international offshore regulators and operators.

Safe Drilling Practices—

- Requires maintaining safe drilling margins and other requirements related to liners and other downhole equipment to help reduce the likelihood of a major well-control event and ensure the overall integrity of the well design.
- Requires monitoring of deepwater and High Pressure High Temperature (HPHT) drilling operations from the shore and in real-time. This will allow operators to anticipate and identify issues in a timely manner and to utilize onshore resources to assist in addressing critical issues.
- Requires daily reports to BSEE concerning any leaks associated with BOP control systems. This will ensure that the bureau is made aware of any leaks so it can determine if further action is appropriate.
- Requires compliance with API RP 17H to standardize ROV hot stab activities. This will allow certain functions of the BOP to be activated remotely.

BOP Testing—

- Requires same pressure testing frequency (at least once every 14 days) for workover and decommissioning operations as for drilling and completion operations. Pressure test results will aid in predicting future performance of a BOP, and harmonizing testing frequencies for all well operations will also help streamline the BOP function-testing criteria and reduce the unnecessary repetition every 7 days of testing in workover and decommissioning operations that could pose operational safety issues.
- Requires additional measures (*e.g.,* RTM and increased maintenance) to help ensure the functionality and operability of the BOP system that will help reduce the safety and environmental risks.

B. Summary of Significant Differences Between the Proposed and Final Rules

After consideration of all relevant and significant comments, BSEE made a number of revisions from the proposed rule in the final rule. We are highlighting several of these changes here because they are significant, and because numerous comments addressed these topics. A discussion of the relevant and significant comments and BSEE's responses are found in part VI of this document. The significant revisions made in response to comments include:

1. Safe Drilling Margin—§ 250.414(c)

In response to one of the *Deepwater Horizon* investigation recommendations—*i.e.,* to better define safe drilling margins—BSEE proposed to revise the safe drilling margin portion of the drilling prognosis (*i.e.,* well drilling procedures) required in an Application for Permit to Drill (APD). Among other things, BSEE proposed that the ''static downhole mud weight must be a minimum of 0.5 pound per gallon (ppg) below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient'' (''the 0.5 ppg drilling margin''). This proposed requirement was typically part of BSEE's approval parameters during the permitting process. However, many commenters expressed concerns that strict enforcement of a 0.5 ppg drilling margin in all circumstances could cause adverse economic consequences because it could effectively require setting additional casing strings and smaller hole sizes and thus, in some cases, could make it impossible to reach target depths. The commenters suggested various alternatives to the 0.5 ppg requirement, including allowing operators to use a risk-based approach to setting safe drilling margins on a case-by-case basis.

Typically, 0.5 ppg is an appropriate safe drilling margin for normal drilling scenarios and has been approved by BSEE (and thus made a requirement) in numerous APDs. However, BSEE understands that there are some well-specific circumstances where a lower drilling margin may be acceptable to drill a well safely, and BSEE has approved appropriate alternative downhole mud weights as part of a safe drilling margin in many APDs. Accordingly, in this final rule, BSEE is keeping the 0.5 ppg drilling margin as proposed to be the default requirement, but is adding a new paragraph (c)(2) to § 250.414 that expressly allows the use of an alternative to the 0.5 ppg drilling margin if the operator submits adequate justification and documentation, including supplemental data (*e.g.*, offset well data, analog data, seismic data, risk modeling), in the APD. This addition is consistent with current BSEE GOMR practice to allow alternative drilling margins when justified and documented. This change will also provide operators some assurance that an alternative drilling margin, other than the 0.5 ppg margin, may be used when appropriate, while helping BSEE ensure the use of drilling mud with properties (*e.g.*, density, viscosity, additives) best suited for a specific well interval and based on well-specific drilling and geological parameters.[9] This addition to the safe drilling margin section will provide increased planning flexibility when drilling into areas that could require lower safe drilling margins, such as depleted sands or below salt (both common occurrences in the GOMR), and help avoid the potential negative consequences of requiring a 0.5 ppg margin in all cases.

BSEE is also making other minor changes to the proposed § 250.414(c). Specifically, as suggested by several commenters, we are replacing the term ''static downhole mud weight'' with ''equivalent downhole mud weight,'' and removing the references to Equivalent Circulating Density (ECD). Several commenters suggested replacing static downhole mud weight with a more appropriate term to better define and assess the mud weight because of the difficulty of achieving and verifying static downhole mud weight during operations. BSEE agrees with this observation. To verify a static downhole mud weight, the well would need to be placed in a static situation. This would be done by turning off the pumps and letting the well sit until it is static; however, that process can result in complications, such as cuttings and debris settling out in the bottom of the well and thermal gradients affecting mud properties. Some of these complications may create additional issues, such as stuck pipe or loss of wellbore integrity. The change from ''static'' to ''equivalent'' allows the downhole mud weight to be based on the mud properties that can be tested at the surface and then calculated to downhole conditions. Thus, equivalent downhole mud weight can be verified on the rig as operations are being conducted.

BSEE also removed the references to ECD from this section based on comments. For the reasons discussed elsewhere in this preamble (with regard to § 250.413), BSEE determined that operators do not need to submit the estimated ECD in the APD permitting process; however, BSEE expects operators to continue their normal practice of considering ECD while drilling.

2. Accumulator Systems

In the proposed rule, BSEE proposed a number of significant changes to existing BOP requirements as well as new requirements for BOPs and associated systems, including new requirements for subsea and surface BOP accumulator systems. (See proposed §§ 250.734 and 250.735.) The purpose of the accumulator system and these new requirements is to ensure that there is sufficient volume and pressure in the accumulator bottles to properly operate BOP components in a specified timeframe regardless of the location of the accumulator bottles. Among other things, we proposed increasing accumulator capacity to operate all BOP functions; *i.e.,* requiring all surface accumulator systems, whether associated with surface or subsea BOPs, to meet the requirements for accumulators servicing surface BOPS under the prior regulations (including the requirement that the accumulator system provide 1.5 times the volume of fluid capacity necessary to hold closed all BOP components). We also proposed requiring surface accumulator systems to operate under MASP conditions, with the blind shear ram being last in the BOP sequence, and still have enough accumulated pressure to allow the BOP to shear pipe and seal the well. In addition, we proposed defining critical functions for BOP operation, and requiring dedicated, independent accumulator bottles for emergency functions (autoshear/deadman/emergency disconnect sequence (EDS)).

BSEE received multiple comments on these proposed provisions. Industry stakeholders raised concerns with (and in some cases suggested revisions to) the proposed requirements, including the following concerns:

- That the proposed surface and subsea accumulator capacity requirements are in conflict with API Standard 53 and API Spec. 16D;
- That the terminology in the proposed rule and the current industry standard (API Standard 53) are inconsistent, and that the different terminology could cause ambiguity and confusion in efforts to comply with a final rule. Industry commenters recommended using the terminology used in the API standard; and
- That the proposed requirement that accumulator systems be able to supply pressure to operate all BOP components and shear pipe as the last step in the BOP sequence, without assistance from a charging unit, would increase the number of accumulator bottles needed and would require upgraded accumulator system controls.

The commenters also stated that costs associated with the additional bottles would be significant and that the extra weight from additional bottles, given limited deck space availability, could cause structural issues with the rig.

- That the proposed requirements that the subsea accumulator system be able to supply pressure to operate all critical BOP components, and that the system have dedicated bottles for each EDS/autoshear/deadman system(s), would greatly increase the number of accumulator bottles on the subsea BOP. The commenters stated that the increased number and weight of accumulator bottles could also cause structural concerns for the BOP frame and the rig and that costs associated with the additional bottles would also be significant.

BSEE reviewed all of the relevant comments and has made changes to the proposed surface and subsea accumulator requirements in the final rule. In this final rule, BSEE is deleting the ''1.5 times volume capacity'' requirement for all surface accumulators, and instead requiring that all accumulator systems (including those servicing subsea BOPs) meet the sizing specifications of API Standard 53. The final rule also extends the effective date to comply with the new accumulator requirements (both surface and subsea) to 5 years; removes the proposed requirement that the surface accumulator be able to operate the blind shear ram as the last function in the BOP sequence; defines ''critical functions;'' and requires dedicated subsea accumulator bottles for autoshear and deadman (but not EDS) functions and allows those dedicated bottles to be shared between the autoshear and deadman functions.

BSEE reevaluated the relevant industry standards and determined that API Standard 53 and API Spec. 16D provide reasonable and appropriate methods to ensure proper volumes and pressures of appropriate BOP components. Changing the proposed

[9] Alternatives to compliance with the 0.5 ppg safe drilling margin requirement could also be requested under existing § 250.141, and approved by BSEE if the criteria of that section are satisfied; but such separate requests would not be necessary if an operator requests an alternative in its APD under new § 250.414(c)(2).

volume requirements for surface accumulators to meet the specifications of API Standard 53 will allow for more specific assessments of the capacity necessary to address unique operating conditions, while still ensuring that there is enough capacity to operate all specified BOP components in an emergency. This will significantly reduce the additional costs identified in industry comments, since it eliminates the ''1.5 times volume'' requirement that the proposed rule would have extended to surface accumulators servicing a subsea BOP, and since most accumulator equipment has been designed to meet the API Standard 53 specifications since that standard was adopted in 2012.

Removing the ''1.5 times volume'' requirement and replacing it with the volume requirements of API Standard 53 also will not decrease safety or environmental protection as compared to the proposed requirement. BSEE determined that the methods for calculating the necessary fluid volumes and pressures in the API standard provide an acceptable amount of usable fluid and pressure to operate the required components, while still ensuring the required 200 pounds per square inch (psi) above the pre-charge pressure. API Standard 53 also discusses the need to have 200 psi remaining on the bottles above the pre-charge pressure after operating the BOP components, which would provide a sufficient margin of error to promote safety and help prevent environmental harm from failure of pressure to the BOP.

Removing the proposed language regarding the blind shear ram being the last in sequence will eliminate industry's misimpression that the proposed language would have mandated that the blind shear ram always be the last step in the BOP sequence. In addition, BSEE agrees with the commenters that the proposed language regarding sequencing of the blind shear ram is not necessary, as long as the accumulator is able to provide sufficient volume of fluid to operate all the required BOP functions under MASP.

BSEE is also making changes in the final rule to the subsea accumulator requirements in response to comments. BSEE is requiring subsea accumulators to have enough capacity to provide pressure for critical functions, as defined in API Standard 53, and to have accumulator bottles that are dedicated to autoshear and deadman functions (but not EDS), and that may be shared between those functions.

Subsea accumulator charge normally comes from the surface, but in an emergency the connections to the surface may be lost and/or the accumulator may have already operated multiple BOP components, which may have reduced the accumulator fluid pressure needed to successfully shear and seal. Dedicated bottles for autoshear and deadman functions would ensure that the subsea accumulator has enough pressure available to operate those emergency systems even if all surface connections are lost or the volume or pressure in the accumulator system are depleted. BSEE determined, however, that permitting those functions to share the dedicated accumulator bottles would not result in a reduction to safety or environmental protection so long as the shared bottles are capable of providing enough pressure to operate the emergency functions. By contrast, dedicated capacity in a subsea accumulator for the EDS is not necessary, since the EDS is serviced through the main (surface) accumulator system by rig personnel.

3. BOP 5-Year Major Inspection

In the proposed rule, BSEE included a provision to require a complete breakdown and inspection of the BOP and every associated component every 5 years, as documented by a BAVO, which, as proposed, could not be performed in phased intervals. BSEE received multiple comments on the 5-year inspection interval. Most industry commenters did not object to a 5-year inspection requirement for each BOP component, provided that the inspections could be staggered, or phased, over time. Commenters expressed concern that requiring all components to be inspected at one time would put too many rigs out of service, potentially for long periods of time, with substantial economic impacts.

Based on consideration of the issues raised in the comments, BSEE has revised the final rule in order to allow a phased approach for 5-year inspections (*e.g.,* staggered inspection for each component), as long as there is proper documentation and tracking to ensure that BSEE can verify that each applicable BOP component has had the major inspection within 5 years. BSEE is also adding, for clarification, the applicable dates for the starting point of the 5-year cycle. BSEE is confident that these inspection requirements maintain the necessary level of safety and environmental protection without resulting in unnecessary interference with scheduling or complications for operations. Requiring operator documentation of the component inspection dates, and requiring those records to be available on the rig, will help BSEE to verify that the components were inspected within the required timeframe and will also assist BSEE's review of the documentation, when requested. The final rule requires that all of the appropriate components be inspected during the 5-year cycle. Proper documentation of phased inspections will improve BSEE oversight, as compared to current practice, while a phased approach will avoid the possibility of long rig shut downs.

4. Real-Time Monitoring

In § 250.724 of the proposed rule, BSEE proposed to require RTM of certain data for well operations that use either a subsea BOP or a BOP on a floating facility, or are conducted in an HPHT environment. Under the proposed rule, the RTM system would have been required to gather and ''immediately transmit'' data on the BOP control system, the well's fluid handling systems on the rig, and the well's downhole conditions with the bottom hole assembly tools (if any) to an onshore facility to be monitored by qualified personnel in ''continuous contact'' with rig personnel during operations. In addition, BSEE proposed that, after transmission, the RTM data must be preserved and stored at a designated location, identified in an APD or APM, and that the location and RTM data be made available to BSEE upon request. Finally, the proposed rule would have required immediate notification to the appropriate BSEE District Manager of any loss of RTM capability during operations and would have authorized the District Manager to require other measures pending restoration of RTM capabilities.

BSEE intends for industry to use RTM as a tool (*i.e.,* as an ''additional pair of eyes'') to improve safety and environmental protection during ongoing well operations, as recommended by several reports on the *Deepwater Horizon* incident. *See* 80 FR 21520. BSEE does not intend that onshore personnel monitoring the RTM data would have operational control over the rig based on the data; rather, BSEE intends that onshore personnel could use RTM data to help rig personnel conduct their operations safely and to assist rig personnel in identifying and evaluating abnormalities and unusual conditions before they become critical issues. In addition, BSEE expects operators to review stored RTM data after operations are complete in order to improve well-control efficiency, training, and incident investigation. Reviewing past data can help improve operations (*e.g.,* understanding well conditions in certain geological formations assists in the collection and use of offset well data to make drilling in similar formations more efficient).

There are many other aspects of RTM that were not addressed in the proposed rule, and that are not addressed in this final rule. In this rulemaking, BSEE is laying the groundwork for further development and use of RTM to help industry to continue improving offshore safety and environmental protection. Industry, academia, BSEE and others are studying and developing new RTM technology and processes, which continues to evolve. BSEE may consider additional guidance or regulatory requirements for use of RTM, as appropriate, in later rulemakings.

BSEE received multiple comments on these issues, expressing concerns with these proposed provisions and suggesting alternatives. A more detailed discussion of the RTM comments is found in section part VI.C of this document. However, some of the industry concerns with the proposed requirements include:

• The meaning of proposed requirements to ''immediately transmit'' these RTM data and to maintain ''continuous contact'' between onshore personnel and rig personnel;

• The proposed requirement that loss of ''any real-time monitoring capability during operations'' requires immediate notification of, and possible action by, the District Manager; and

• The potential for an increase in rig personnel response time and a decrease in the accountability of the offshore personnel.

In addition, several commenters suggested that BSEE require operators to develop specific RTM plans in lieu of some or all of the proposed requirements, or that the existence of such plans would justify BSEE eliminating some or all of the proposed RTM requirements, even if an RTM plan were not expressly required.

BSEE considered all of the relevant comments and made several revisions and clarifications to the proposed RTM requirements in final § 250.724. The final rule removes or replaces several provisions that were perceived by commenters as overly prescriptive with more flexible, performance-based measures that better reflect BSEE's intention that operators use RTM as a tool to improve their own ability to prevent well control incidents while providing BSEE with sufficient access to RTM information to evaluate system improvements. For example, instead of requiring an operator to notify the District Manager immediately of any loss of RTM capabilities, as proposed, the final rule requires an operator to have an RTM plan that specifies how the operator will notify BSEE of any significant interruption in monitoring or RTM communications. The revisions to the final rule also clarify that BSEE did not intend to require that direct operational responsibility for well control be shifted from rig personnel to onshore RTM personnel.

Specifically, the revisions to the proposed requirements, as reflected in the final rule include the following:

• The phrase ''all aspects of'' was deleted from paragraphs (a)(1), (2), and (3).

The deletion of that phrase provides for a more performance-based rule, pursuant to which the operator, based upon the particular rig configuration and situation, would determine the data to be collected. Further, the deletion of ''all aspects of'' provides more operator flexibility so as to reduce the probability of an increase in response time while maintaining the accountability of the offshore personnel. This revision also clarifies that RTM is intended to be used as a support tool for the existing rig-based chain of command and is not a substitute for the competency or well-control responsibilities of the rig personnel.

• The word ''data'' was added to clarify the systems and tools from which real-time data must be gathered and monitored.

BSEE also made the following revisions and clarifications in final § 250.724(b):

• The phrase ''barring unforeseeable or unpreventable interruptions in transmission'' was added to address concerns about the interruption of the transmission of the data.

• The word ''immediately'' was deleted with respect to transferring data to shore, and the phrase ''during operations where they must be monitored [by qualified personnel] who must be in continuous contact with rig personnel during operations'' was deleted. These revisions were made to address concern that mandatory onshore monitoring would result in an erosion of authority of, or shifting operational decision making away from, the rig-site personnel. These revisions also address concerns that mandatory onshore monitoring and continuous rig-to-shore contact might result in an increase in response time and a decrease in the accountability of the offshore personnel. They also clarify BSEE's intent that RTM involving onshore personnel serve as a support tool for the existing rig-based chain of command.

BSEE also revised and clarified final § 250.724(c) by deleting the sentences that proposed that operators who lose any RTM capability during operations covered by the section, you must immediately notify the District Manager, and that the District Manager may require other measures until RTM capability is restored.

BSEE replaced the deleted sentences with a performance-based requirement for operators to have an RTM plan, as suggested by several industry commenters, that addresses several of the issues that the proposed rule would have addressed through prescriptive language. For example, most of the commenters' concerns with proposed paragraph (c) appear to be based on the assumption that the proposed language would have required every interruption in RTM capabilities—no matter how brief or inconsequential—to be reported to the District Manager, and would have resulted in orders to suspend operations in every case. However, BSEE did not intend that proposed requirement to apply to minor or routine interruptions in RTM capabilities that pose no significant risk to safety or of a LWC. Accordingly, the final rule now requires operators to have RTM plans that include procedures for responding to and notifying BSEE of ''significant and/or prolonged interruptions.'' Thus, BSEE anticipates that the final rule will result in essentially the same results regarding interruptions that the proposed rule was intended to achieve, with no loss of safety or environmental protection as compared to the proposal.

Specifically, the final rule requires that the RTM plan be made available to BSEE upon request and that the plan include descriptions of:

• RTM technical and operational capabilities;

• How the RTM data will be transmitted onshore, how the data will be labeled and monitored by qualified onshore personnel, and how the data will be stored onshore;

• A description of procedures for providing BSEE access, upon request, to the RTM data including, if applicable, the location of any onshore data monitoring or data storage facilities;

• Onshore monitoring personnel qualifications;

• Methods and procedures for communications between rig and onshore personnel;

• Actions that will be taken in case of loss of RTM capabilities or rig-to-shore communications; and

• A protocol for responding to significant or prolonged interruptions of

RTM capabilities or communications, including procedures for notifying the District Manager of such interruptions.

5. Potential Increased Severing Capability

As discussed in the notice of proposed rulemaking, BSEE proposed a variety of requirements that would increase the likelihood that a BOP would be able to sever a drill string in an emergency situation in order to shut-in the well and prevent a catastrophic blowout. (*See* 80 FR 21509–21510, 21529.) However, there are a variety of components in the drill string (*e.g.,* drill collars) that cannot be severed using currently available technology. (*See id.* at 21509.) Accordingly, the notice of proposed rulemaking expressly stated that BSEE was considering including an additional provision in the final rule that would require operators to ''install technology that is capable of severing any components of the drill string (excluding drill bits) . . . within 10 years from publication of the final rule.'' (*See id.* at 21529.) BSEE explained that this performance-based requirement would provide additional protection against potential LWC in an emergency by requiring installation of new technology that could sever components of a drill string (*e.g.,* drill collars) that cannot be severed using current shear rams.

BSEE also explained that it was considering a 10-year timeframe for compliance with this potential requirement in order to provide time for manufacturers or operators to develop or select innovative or improved technologies or equipment to meet the requirement. BSEE then invited public comments and supporting data on a variety of key technical and economic questions and issues that would help BSEE decide whether to include such a requirement in the final rule. (*See id.* at 21529–21530.)

Only a small number of comments addressed this severing issue. Several industry commenters opposed the idea or stated that it would be extremely difficult and expensive to meet, and that even 10 years might not be long enough to come into compliance. One commenter suggested that BSEE require that shearable sections be designed into the drill string (instead of requiring that everything be shearable), and that a shearable section of the drill string must be across one of the shearing rams at all times. The same commenter asserted that shearable drill collars currently exist, but did not provide any additional technical or economic information supporting that assertion. Another commenter supported the requirement in general, but suggested that it should be implemented in less than 10 years. None of the comments, however, provided adequate relevant technical or economic data or other information to help BSEE determine whether to include the requirement in the final rule.

Accordingly, although BSEE still believes that such a severing requirement could provide important additional controls to prevent future well-control events and catastrophic blowouts, such as the *Deepwater Horizon* incident, BSEE has decided that it needs more time and more information to make a final decision about whether to adopt such a severing requirement. Therefore, BSEE will review severing technology on a periodic basis, with the intention of concluding the review no later than seven years from the publication of this final rule. BSEE will conduct a retrospective review of this rule under E.O. 13563, according to DOI's regulatory review plan. If, after obtaining and considering additional information, BSEE decides to proceed with adoption of such a regulation, BSEE will propose to do so in a separate rulemaking document.

6. BOP Pressure Testing Interval

BSEE received a number of comments on proposed § 250.737(a)(2), which proposed to harmonize the pressure testing interval for BOPs used in workovers and decommissioning operations (currently 7 days) with the existing 14-day interval for pressure testing BOPs used in drilling and completion operations.

In the proposed rule, BSEE explained that increasing the test interval for workover and decommissioning BOPs from 7 days to 14 days could decrease wear and tear on those BOPs, and thus increase their durability and reliability in the long-term and otherwise potentially improve safety. (*See* 80 FR 21511.) BSEE also explained that it expected that BOP equipment meeting the other proposed new requirements would perform more reliably than previous equipment, thus making 7-day testing for workover and decommissioning BOPs less crucial. (*See id.* at 21524.)

In addition, BSEE requested comments on whether the pressure testing interval for BOPs used in all types of operations should be 7 days, 14 days (as proposed), or 21 days. BSEE also requested comments on the potential cost implications of each of those intervals. (*See id.* at 21511.) In its initial economic analysis for the proposed rule, BSEE estimated the potential savings from increasing the pressure testing interval from 7 to 14 days for workover and decommissioning BOPs to be about $150 million per year, and the potential cost savings that would result from increasing the testing interval for all BOPs from 14 to 21 days to be approximately $400 million per year.

In response, one commenter suggested that BSEE require more frequent BOP pressure tests (*i.e.,* every 7 days for all BOPs used in Arctic OCS operations), and claimed that BSEE had not justified changing the 7-day testing requirement for workover and decommissioning BOPs to 14 days. However, most commenters, primarily from industry, supported increasing the pressure testing interval for workovers and decommissioning and recommended increasing the testing interval for all BOPs to 21 days. Commenters cited API Standard 53, which recommends a 21-day BOP test cycle for shear ram BOPs, as well as international industry best practices, in support of longer pressure test intervals. Multiple commenters also pointed out that less frequent testing would mitigate wear and tear on the equipment from the testing itself, and that wear and tear adversely affects long-term reliability of the equipment and thus increases the risks of equipment failure. Some commenters also referred to past joint industry research projects and studies, which they suggested support test intervals longer than 14 days.

BSEE has long been involved with joint industry projects and studies on BOP reliability and, after reviewing the comments on the proposed rule, has concluded that increasing the test interval for workover and decommissioning BOPs from 7 to 14 days is appropriate in terms of decreasing wear and tear and increasing long-term reliability of those BOPs. BSEE and the industry now have substantial experience with the efficacy of the longstanding 14-day testing requirement for BOPs used in drilling and completion operations, and BSEE believes that testing decommissioning and workover BOPs every 14 days will avoid the extra wear and tear and safety risks inherent in 7-day testing and will not result in any diminution of safety and environmental protection as compared to 7-day testing.

BSEE is not aware, however, of any new data that justifies increasing the BOP pressure testing interval for all BOPs from 14 days to 21 days. The previous studies and data on BOP testing frequency that were submitted to MMS prior to the *Deepwater Horizon* incident, as mentioned by some commenters, were not deemed by MMS sufficient to justify increasing the pressure testing interval from 14 to 21 days. In the proposed rule, BSEE explained that it was reevaluating this issue and requested additional data and technical analysis regarding the proposed pressure testing frequency requirements to determine if a uniform 21-day testing interval should be included in the final rule. Given the operational issues that had previously been brought to BSEE's attention by the industry, and the potential costs savings ($400 million dollars per year) that BSEE estimated could result from moving from 14-day to 21-day testing, BSEE anticipated that significant technical and economic comments would be submitted on this issue. Comments in support of such a change were submitted; however, these comments did not provide adequate data and information to reasonably support a 21-day testing interval at this time.

BSEE is aware of concerns that the more frequently BOPs are tested, the more likely the equipment is to wear out prematurely; however, it does not automatically follow that every extension of test intervals always increases reliability, and thus safety and environmental protection, in the long-term. The industry commenters do not dispute that testing must occur at appropriate intervals to provide assurance that BOPs will function as intended when needed to prevent a blowout. BSEE's experience with 14-day pressure testing for drilling and completion BOPs indicates that it is effective for its purpose and that, in the absence of significant new information on longer test intervals, it is appropriate to retain that interval for such BOPs and to apply the same requirement to workover and decommissioning BOPs.

BSEE believes that the provisions in the final rule that increase the exchange of data on equipment reliability, that improve the design, manufacturing, maintenance and repair of BOP equipment, and that require the use of BAVOs or other independent third-parties to verify and document BOP testing, repairs and maintenance will result in improved performance and reliability of BOPs in the future. However, in the absence of new data demonstrating that 21-day testing would be as protective as 14-day testing, BSEE has decided to finalize the proposed 14-day pressure testing requirement for BOPs used in all types of operations. In response to the *Deepwater Horizon* incident, industry attempted to voluntarily improve the overall reliability of well control equipment through better designs, improved manufacturing processes, better maintenance and repair procedures, and increased data sharing. BSEE will consider the possibility of adopting 21-day BOP testing when it receives adequate new (post-*Deepwater Horizon*) data and analyses demonstrating that BOP reliability and capability, and personnel safety, are not adversely affected (or are actually improved) by pressure testing at 21-day intervals. This could include, for example, data from BOP testing and usage in OCS or other waters. BSEE will consider relevant data, along with any data indicating that the other requirements contained in this rule (such as BAVO verification), have increased overall BOP performance and reliability and decreased the risk of failure of the systems and components. In the meantime, any operator that believes its specific circumstances warrant a longer pressure test interval may seek approval from the District Manager to use alternate procedures or equipment under § 250.141.

C. Other Differences Between the Proposed and Final Rules

In addition to the significant changes discussed in the preceding section, BSEE has also made changes to the rule in response to comments suggesting that BSEE eliminate redundancy, clarify some potentially confusing language, streamline the regulatory text, and align certain provisions in the proposed regulatory text more closely with relevant terminology in API Standard 53 (where BSEE intended the proposed provisions to be consistent with that standard). In some cases, we agreed with and accepted specific wording changes suggested by the commenters, and in some cases we made changes based on our agreement with the commenters' basic suggestion, even though the commenter provided no specific alternative language or we did not agree with the specific wording suggested by the commenter. In still other cases, we made minor revisions to proposed provisions in order to correct grammatical errors, eliminate potential ambiguity, or to avoid confusion by further clarifying the intent of the proposed language. The revisions include the following:

- In final § 250.292, we clarified the proposed language about pipeline free standing hybrid risers ''on a permanent installation.''
- In final § 250.421, we clarified the proposed language regarding cementing the liner lap and what actions are necessary when an operator is unable to meet the cementing requirements of the liner lap section.
- In final § 250.462, we revised the language from ''pressure holding'' to ''pressure containing'' critical components. We also clarified language on excluding downhole safety valves. And we clarified the equipment that operators must make available to BSEE for inspection. We revised this section to clarify the differences between collocated equipment and SCCE (*e.g.,* collocated equipment includes dispersant injection equipment.)
- In final §§ 250.518, 250.619, and 250.1703, we clarified that, for the purposes of those sections, permanently installed packers and bridge plugs must comply with the referenced industry standard.
- In final § 250.703, we replaced ''the most extreme service conditions'' with ''the maximum environmental and operational conditions'' to which equipment may be exposed at a given well.
- In final § 250.711, we clarified that the same well-control drill cannot be repeated consecutively with the same crew, in order to avoid overly narrow training for certain personnel and to improve proficiency in well-control procedures by a broader set of rig personnel without unduly limiting the operator's discretion to schedule important drills.
- In final § 250.712, we changed the timeframe for informing BSEE of the rig movement from 72 hours to 24 hours' notice before movement. BSEE agreed with commenters that requiring 72 hour notice may have necessitated additional revisions to the submitted form due to the constant changes of operations affecting rig movements. Requiring a 24 hour notification provides a better indication of when a rig will move.
- In final § 250.713, we deleted the reference to ''lift boats'' and made other minor changes to improve consistency in rig-related terminology.
- In final § 250.715, we also revised the language to provide more consistency in rig-related terminology and to clarify the requirements for access to GPS data.
- In final § 250.721, we clarified that operators must test the liner-top, instead of the liner-lap, and that the pressure testing of the entire well should not exceed 70 percent of the burst rating limit of the weakest component.
- In final § 250.722, we clarified that calculations must be included if an imaging tool or caliper is used.
- In final § 250.730, we:
  - Clarified that the lessee or operator must ensure that the BOP systems are designed, installed, maintained, inspected, tested and used properly (instead of the lessee or operator

actually performing these actions themselves), since these actions are usually performed by contractors.

○ Clarified that the working pressure rating for annulars does not need to exceed MASP.

○ Clarified that the BOP system (instead of each ram) must be capable of closing and sealing the wellbore at all times and provide reliable means to handle well-control events.

○ Clarified paragraph (a)(2) to provide that the BOP systems must meet the provisions of the specified industry standards that apply to BOP systems.

○ Revised the failure reporting procedures in paragraph (c) to include submitting such reports to BSEE.

○ Clarified paragraph (d)(1) to remove the reference to the alternative compliance regulations at § 250.141.

• In final § 250.732, we:

○ Revised paragraph (a) by extending the compliance date for BAVO-related requirements to 1 year from the date BSEE publishes a BAVO list and adding new paragraphs (a)(1) and (2). Final paragraph (a)(1) provides that, until the requirements to use BAVOs become effective, operators must use an independent third-party to provide the certifications, verifications, and reports that a BAVO must provide after the BAVO requirements become effective. Final paragraph (a)(2) clarifies the criteria for independent third-parties, based on the longstanding criteria in use under current regulations.

○ Revised paragraph (b)(1)(vi), by replacing ''all testing results'' with ''relevant testing results.''

○ Revised paragraph (d)(6) to clarify that training for personnel who service, repair or maintain BOPs must cover ''any applicable'' OEM requirements.

• In final § 250.733, we removed redundant requirements that are covered in other sections.

• In final § 250.734, we:

○ Revised the ROV provisions to require opening and closing of ram locks, one pipe ram, and the Lower Marine Riser Package (LMRP) disconnect.

○ Clarified that the ROV crew must be capable of carrying out appropriate tasks during emergency operations.

○ Simplified paragraph (a)(6)(vi) by deleting a phrase that would have required a failsafe system to use ''logic'' that makes every step independent from the previous step, and inserting instead the words ''once activated.''

○ Clarified in paragraph (a)(7), that if an operator chooses to ''use'' an acoustic control system there are applicable requirements to demonstrate that it will function in the proposed environment and conditions.

○ Clarified that control panels must have ''enable'' buttons or similar features to ensure two-handed operation.

○ Clarified that there must be a side outlet installed below the lowest sealing shear ram.

○ Clarified that, if there are dual annulars, a gas bleed line must be installed below the upper annular.

○ Revised the language regarding testing of the equipment after making repairs, and clarified the testing requirements under certain circumstances.

• In final § 250.735, we revised paragraph (e), to clarify the required location of the kill line, and paragraph (g) to eliminate the proposed requirement for hydraulically operated locks for pipe rams on surface BOPs and to replace the proposed requirement for hydraulic locks on surface BOP blind shear rams with a requirement for remotely-operated locks.

• In final § 250.736, we revised the kelly valve requirements to better reflect current practice and technology.

• In final § 250.737, we:

○ Clarified, in paragraph (d)(2), that water must be used to do the initial test for surface BOP systems, but that drilling/completion/workover fluids may be used to conduct subsequent tests.

○ Clarified the requirements for testing pods between control stations.

○ Removed redundant provisions covered under other sections.

• In final § 250.738, we:

○ Revised paragraph (a) by removing the requirement to notify the District Manager of problems or irregularities ''including leaks''; however, these problems or irregularities must be recorded on the daily report, which must be made available to BSEE upon request.

○ Revised paragraph (e) to clarify that one set of pipe rams (instead of two) must be capable of sealing around the smaller size pipe.

○ Revised paragraph (f) to clarify the required testing of the connections if casing rams or casing shear rams are installed in a surface BOP stack.

○ Revised paragraph (l) to clarify the required testing of the wellhead/BOP connection if a test ram is to be used.

○ Revised paragraph (p) to clarify the requirements that apply if the bottom hole assembly needs to be positioned across the BOP.

• In final § 250.739, we clarified personnel training and records requirements.

• In final § 250.746, we added a reference to digital recorders, clarified the actions required when there are leaks associated with a BOP control system, and made minor changes to provide consistency in rig-related terminology.

• In final §§ 250.414(k), 250.713(e), 250.714(e), 250.721(d) and (g)(3), 250.722(a)(1), 250.734(a)(7), 250.738(o), 250.740(g), 250.743(c), and 250.744(a), we clarified the purposes for which District Managers may require additional information, testing, or other procedures consistent with the purposes of those sections.

VI. Discussion of Public Comments on the Proposed Rule

In response to the proposed rule, BSEE received over 172 sets of comments from individual entities (*e.g.,* companies, industry organizations, non-governmental organizations, and private citizens). Some entities submitted comments multiple times. All relevant comments are posted at the *Federal eRulemaking* portal: *http://www.regulations.gov.* (To access the comments at that website, enter BSEE–2012–0002 in the Search box.) BSEE reviewed all comments submitted. Each of the following sections contains a brief summary of the relevant and significant comments as well as BSEE's responses.

A. Requests for Extension of the Proposed Rule Comment Period

Summary of comments: BSEE received requests from various stakeholders asking BSEE to extend the comment period on the proposed rule. The majority of those requests sought extensions of 120 days, which would have tripled the length of the original 60-day comment period. BSEE also received a written comment from another stakeholder urging BSEE not to extend the comment period because the proposed rule has been in development since the *Deepwater Horizon* incident, is based on recommendations resulting from that incident, and represents a critical regulatory improvement that should be finalized without delay.

• *Response:* BSEE considered those requests and determined that extending the original 60-day comment period by an additional 30 days provided sufficient additional time for review of and comment on the proposal without unduly delaying a final rulemaking decision. The comment extension to the notice of proposed rulemaking was published in the **Federal Register** on June 3, 2015. (*See* 80 FR 31560.)

Summary of comments: Various commenters asserted that even the 90-day public comment period was inadequate for a rule of this technical complexity, and that additional time (*e.g.,* 120 days) was needed to properly address the substantial amount of technical content and complexity in this draft. They suggested that the comment period should be reopened and/or that BSEE publish a revised proposed rule for comment.

- *Response:* BSEE believes that the 90-day comment period, which includes the 30-day extension granted by BSEE, was reasonable and sufficient under the Administrative Procedure Act (APA). The APA requires that agencies give ''interested persons an opportunity to participate'' in the rule making process through submission of written data, views or arguments. (*See* 5 U.S.C. 553(c).) The APA does not prescribe the number of days that an agency must allow for written comments, and an agency's decision on comment period length is generally deferred to unless it is arbitrary and capricious. (*See* 5 U.S.C. 706(2).)

B. Summary of General Comments on the Proposed Rule

1. Comments Supporting the Proposed Rule

Summary of comments: Multiple commenters commended the efforts by BSEE to improve safety and environmental protection and expressed their support for many of the changes in the proposed rule.

- *Response:* It is BSEE's continued mission to promote safety, protect the environment, and conserve resources offshore through vigorous regulatory oversight and enforcement. This final rule is an important step toward better well control and improved safety and environmental protection.

2. Legal Comments

Summary of comments: Several commenters claimed that BSEE failed to incorporate the principles of best available and safest technologies (BAST) reflected in OCSLA, resulting in requirements that are arbitrary, not reasonable or practicable, not economically or technically feasible, less safe, and more obstructive to OCS oil and gas development, in violation of the OCSLA-mandated balance between safety and environmental protection and expeditious and orderly development of OCS resources.

- *Response:* BAST requirements, as set out in OCSLA and its implementing regulations (*see* 30 CFR 250.107) are the product of specific BSEE analyses and determinations. Existing BSEE regulations and this final rule contain numerous technology requirements, all of which were adopted through notice and comment rulemaking. The proposed rule explained the justifications for codifying the technological requirements in the final rule, many of which were derived from recommendations based on exhaustive investigations and reports on the *Deepwater Horizon* incident, and on input from experts representing equipment manufacturers, the offshore oil and gas industry, government, academia, and environmental organizations focused on identifying appropriate technological standards. BSEE believes that the requirements in this regulation provide an appropriate level of safety. BSEE may make a separate determination in the future related to the use of BAST, pursuant to OCSLA, if supplemental requirements are necessary.

Summary of comments: Several industry commenters claimed that certain provisions in the rule could render leases uneconomical to operate, thereby requiring a Takings Implication Analysis (TIA) by BSEE under Executive Order (E.O) 12360, and potentially amounting to a breach of contract by DOI.

- *Response:* By their own terms, OCS oil and gas leases expressly state that they are subject to regulations promulgated after lease issuance, including the types of regulatory action reflected in this final rule. Accordingly, the adoption of this final rule is consistent with lessees' rights to conduct operations on the OCS—which are derived entirely from their lease interests—and thus do not amount to a breach of contract or a taking under the Fifth Amendment. As a result, a TIA is not necessary.

E.O. 12630 requires executive agencies to review agency actions, including rulemakings, that have takings implications (*i.e.,* actions that, if implemented, could effect a taking) to prevent unnecessary takings and to identify and discuss any significant takings implications and the agency's conclusions on the takings issues. In this case, the terms of all OCS oil and gas leases allow BSEE to promulgate new rules, pursuant to OCSLA, without violating the rights created by the lease contracts. Specifically, leases issued prior to 2010 state:

> This lease is issued pursuant to the Outer Continental Shelf Lands Act. . . . The lease is issued subject to the Act; all regulations issued pursuant to the Act and in existence upon the Effective Date of this lease; all regulations issued pursuant to the statute in the future which provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf and the protection of correlative rights therein, and all other applicable statutes and regulations.

Leases issued since 2010 likewise provide that:

> This lease is subject to [OCSLA], regulations promulgated pursuant thereto, . . . and those . . . regulations promulgated thereafter, except to the extent they explicitly conflict with an express provision of this lease. It is expressly understood that amendments to existing . . . regulations . . . as well as the . . . promulgation of new regulations, which do not explicitly conflict with an express provision of this lease may be made and that the Lessee bears the risk that such may increase or decrease the Lessee's obligations under the Lease.

None of the provisions of this rule explicitly conflict with any express provisions of OCS oil and gas leases.

The Supreme Court and other Federal courts have interpreted the relevant lease language to mean that ''[a] change to an OCSLA regulation does not breach the express terms of the lease language.'' *Century Exploration New Orleans, LLC* v. *United States,* 745 F.3d 1168, 1178 (Fed. Cir. 2014), *citing Mobil Oil Exploration & Production Southeast, Inc.* v. *United States,* 530 U.S. 604, 616 (2000); *Century Exploration New Orleans, LLC* v. *United States,* 110 Fed. Cl. 148, 164–66 (2013) (the lease language ''allocates the risk of certain legal changes—future regulations issued pursuant to OCSLA—to [lessees]''). This conclusion is in no way dependent upon the impacts of such a rulemaking on the economics of lease development.

The express language of the leases (in sections 10 and 12) likewise requires that the lessee comply with all applicable regulations, and OCSLA expressly provides that regulations promulgated pursuant to the statute apply to both new and existing leases as of their effective date. 43 U.S.C. 1334(a). Because all changes to the regulatory language implemented through this rule are made pursuant to OCSLA, they are expressly incorporated into the terms of the leases and thus consistent with lessees' rights thereunder. In light of the fact that the entirety of lessees' rights to conduct the impacted operations on the OCS are derived from their leases, regulation that is consistent with those lease rights likewise cannot amount to an unconstitutional taking of those lease rights. Accordingly, promulgation of this rule does not amount to a breach of any lease terms or a taking of any rights derived from OCS leases.

Summary of comments: Some commenters raised issues concerning the World Trade Organization's (WTO's) Technical Barriers to Trade Agreement (TBT Agreement). In particular, the commenters asserted that purported inconsistencies between the proposed rules and API Standard 53 require compliance with notification procedures under the TBT Agreement.

• *Response:* The TBT Agreement seeks to avoid unnecessary obstacles to international trade, in part by requiring that technical regulations and conformity assessment procedures be consistent with international standards promulgated by international standards developing organizations.

The proposed rule does not create a technical barrier to trade because it is neutral as to the national origin of regulated equipment. The proposed rule did not, and this final rule will not, discriminate in favor of U.S.-fabricated equipment. The final rule is equally applicable to all relevant equipment, regardless of the equipment's country of origin. Accordingly, BSEE's proposed rule did not, and the final rule does not, create an unnecessary technical barrier to trade.

3. Arctic-Related Comments

Summary of comments: Multiple commenters recommended extending certain equipment, testing and monitoring requirements in the proposed rule to all operations on the Arctic OCS, where some of those operations would not have been covered under the terms of the proposed requirements. For example, some commenters recommended that BSEE require a second set of blind shear rams to be installed in the BOP stack for all operations in the Arctic, including surface BOPs on gravel and ice islands and bottom-founded structures in the Arctic, even though the proposed requirement was only intended to apply to surface BOPs on floating facilities (*See* § 250.733(b)(1)).

Commenters also suggested that all BOPs used on the Arctic OCS undergo independent verification by a qualified third-party organization, and that Arctic operators submit to BSEE an annual Mechanical Integrity Assessment (MIA) Report prepared by a BAVO, even though BSEE proposed that the MIA Report requirement apply only to subsea BOPs, BOPs in HPHT environments, and surface BOPs on floating facilities. The commenters asserted that extending these requirements would ensure that each BOP used on the Arctic OCS is fit for Arctic OCS service. Commenters also suggested extending to all Arctic OCS facilities: the proposed requirements in § 250.724 for RTM for subsea BOPs, BOPs in HPHT environments, and surface BOPs on floating facilities; and the proposed Source Control and Containment requirements in proposed § 250.462 for subsea BOPs or surface BOPs on floating facilities.

Some commenters also requested that BSEE revise the existing regulations to strengthen equipment and operational requirements for equipment used on the Arctic OCS. These suggestions included: Requiring Arctic operators to submit a cementing protocol and quality assurance plan, prepared by an experienced Arctic drilling engineer, as part of their APD; daily well activity reporting requirements for the Arctic OCS; and mandatory use of cement evaluation tools and temperature logs.

Some of the comments were expressly related to provisions in BSEE's proposed rule, ''Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf.'' (*See* 80 FR 9916 (Feb. 24, 2015).) The commenters stated that they submitted the same comments to BSEE in response to that proposed rule.

• *Response:* The requirements in this final rule apply to any OCS facility in any BSEE region (GOM, Pacific, Alaska), including an Arctic OCS facility, that meets the general conditions for applicability stated in the specific regulatory provisions. For example, some provisions (such as § 250.730—What are the general requirements for BOP systems and system components?) apply nationwide to all BOPs on all OCS facilities, including any facility with a BOP on the Arctic OCS. Other requirements apply only to specific types of facilities or equipment or BOP systems (such as the requirements in § 250.733, which apply only to surface BOP stacks, and the requirements in § 250.734, which apply only to subsea BOPs). And some provisions apply to any facility or BOP that meets specific conditions, such as § 250.732(d), which requires an operator to submit an annual MIA report for any subsea BOP, BOP in an HPHT environment, or surface BOP on a floating facility. In any case, all of the provisions in this final rule apply without regard to the OCS region in which the facility or BOP is operating.

BSEE recognizes that the Arctic OCS presents a uniquely challenging operating environment, characterized by extreme environmental conditions, geographic remoteness, and a relative lack of fixed infrastructure and existing operations. However, many of the comments submitted on the Arctic OCS issues are outside the scope of this well-control rulemaking. BSEE has decided to address Arctic-specific issues in separate rulemakings, guidance documents, or on a case-by-case basis as needed. Most of the comments related to the Arctic that were submitted under this rulemaking were also submitted in response to the proposed Arctic OCS exploratory drilling rule proposed in February 2015 and will be considered by BSEE in that rulemaking.

4. General Comments

a. ''Grandfathering'' of Certain Equipment Requirements

Summary of comment: Multiple commenters asserted that it is not clear whether existing facilities will be ''grandfathered in,'' (*i.e.,* that the final requirements would apply only to new facilities or equipment installed after the final rule's effective date), or whether existing facilities will have to comply with all provisions of the final rule, even if that requires, for example, installing new equipment or retrofitting existing equipment, which the commenters claimed would be very expensive and burdensome.

Similarly, some commenters asserted that it is not clear whether existing equipment already under construction or in fabrication will have to comply with the new regulations in the event that the new regulations are published or become effective during or after fabrication, but prior to startup of new facilities or actual installation of the equipment. The commenters asserted that, under this interpretation, compliance may not be possible to achieve without significant delay and associated costs.

A commenter stressed that application of manufacturing specifications (*e.g.,* API Spec. 16A, Spec. 16C, and Spec. 16D), incorporated by reference in certain provisions of this rule, to existing equipment would effectively preclude the use of such equipment. The commenter also claimed that BSEE had not considered the cost of application of those standards in the initial economic analysis for the proposed rule.

• *Response:* During the rulemaking process, BSEE makes a determination about how or whether new and revised regulations will apply to existing operations, equipment, and facilities during the rulemaking process. As a general matter, OCSLA provides that all regulations promulgated thereunder (including this rule) ''shall, as of their effective date, apply to all operations conducted under a lease issued or maintained under'' OCSLA. (43 U.S.C. 1334(a).)

When BSEE decides to exempt existing operations, equipment, or facilities from a specific provision, BSEE makes that clear in the regulatory text or relevant preamble discussions for the rule. In this rulemaking, each of the specific requirements for equipment or facilities will apply to the equipment or facilities that are described in that provision, without regard to whether the facility or equipment already exists, unless specifically stated otherwise. For example, (as discussed elsewhere in this document), § 250.733(b)(2) of the final rule requires use of a dual bore riser configuration on facilities that plan to use surface BOPs on floating production facilities, if risers are installed 90 or more days after publication of the final rule (*e.g.,* at the effective date of the rule). This means that existing surface BOPS on floating facilities using single bore risers installed less than 90 days after the publication of the final rule (*e.g.,* before the effective date of the rule) are not required to be retrofitted with dual bore risers.

BSEE notes that many of the requirements in this final rule are not new, but are the same as or very similar to longstanding requirements in the existing regulations. Thus, those requirements will simply continue to apply to existing facilities or equipment. In addition, several of the most significant new requirements in this rule do not require compliance for several years—or longer in some cases (see part III of this document)—so the impact of those requirements on existing facilities or equipment will be substantially mitigated by those extended compliance periods (*e.g.,* some equipment potentially affected by some new requirements may already be due for replacement or major updates by the time such new requirements take effect). If there are unique circumstances that indicate that use of some equipment or procedures, other than as specified in this final rule, may be warranted, an operator may seek approval to use alternate equipment or procedures under existing § 250.141, if the operator can demonstrate that such equipment or procedures will provide a level of safety and environmental protection that equals or surpasses these requirements.

b. Requests for Additional Workshops

Summary of Comments: Numerous commenters recommended that BSEE hold additional workshops related to this rulemaking. Most of those commenters recommended that BSEE postpone finalizing the proposed rule, reopen the public comment period, and hold workshops during the new comment period before adopting a final rule. Some commenters, however, suggested that BSEE hold workshops after adopting the final rule, in order to further the industry's understanding of the provisions of this rulemaking. Commenters discussed a number of issues that they asserted warranted such workshops. One commenter stated that industry concerns over perceived technical flaws in, and potentially significant impacts from, the proposed rule, and the limited time provided to comment on the proposal, warranted workshops or some other form of engagement between BSEE and industry to make sure that the regulations are technically viable, provide optimum risk management, and are in the best interest of America's economy and domestic energy security.

A commenter expressed concerns that the proposed rule, as written, would not achieve BSEE's actual goals. This commenter suggested that BSEE should arrange workshops with industry to discuss the meanings of the proposed rules and revise the rules to improve safety while reducing unintended consequences.

• *Response:* As previously discussed in this document, BSEE actively engaged—in meetings, training, workshops and other forums—with many stakeholders, including industry, for several years prior to and during development of the proposed rule. In particular, BSEE convened Federal decision-makers and stakeholders from the OCS industry, academia, and other entities at a public forum on offshore energy safety on May 22, 2012, to discuss ways to address well-control concerns arising from the *Deepwater Horizon* incident investigations. Those investigations and the May 2012 forum resulted in numerous recommendations to enhance safety and environmental protection of offshore operations by improving well control and BOP performance. BSEE recognized the importance of collecting the best ideas, from all perspectives, on the prevention of well-control incidents and blowouts to assist BSEE in developing this rule. This included industry's valuable knowledge and skillsets.

BSEE received significant input and specific recommendations from many industry groups, operators, equipment manufacturers, academics and environmental organizations as a result of the 2012 forum. Subsequently, BSEE sought and received additional input on potential means to improve well control through BSEE attendance at industry and public conferences, industry standards committee meetings, and BSEE's own standards workshops. BSEE also invited industry assessments of BSEE-funded technology research projects related to well control. BSEE conducted at least 50 meetings with various companies, trade associations, regulators, and other stakeholders interested in well control as part of this process.

BSEE considered all of this input in developing the proposed rule published in April 2015. (*See* 80 FR 21508–21509.) Subsequently, at the request of several commenters, including industry commenters, BSEE extended the comment period for the proposed rule to 90 days, so commenters would have even more time to develop and present their views and relevant information.

Subsequently, BSEE received over 170 comments on the proposed rule, some extremely detailed, covering almost every section of the proposed rule, and hundreds of which related to specific technical, economic and other issues. Many of the comments were submitted by members or representatives of the offshore oil and gas industry, as well as environmental groups, academics, other Federal agencies, and interested members of the public. BSEE subject matter experts (including experienced engineers and economists) carefully considered all of the relevant and significant comments in developing this final rule. As discussed elsewhere in this document, BSEE not only responded to those comments, but made a number of revisions to the final rule to address concerns or information described in the comments.

In light of all of these efforts, BSEE does not agree with the commenters that urged BSEE to delay this final rule pending more workshops. BSEE intends to stay fully engaged with the affected industry and other stakeholders as this rule is implemented, and expects to participate in future meetings and workshops where the issues in this rulemaking will continue to be discussed. As experience and additional information are gained under this rule, BSEE will both provide guidance and clarification on this rule, as necessary.

c. Licensed Engineers

Summary of Comments: A commenter recommended that BSEE require the use of a licensed engineer at every stage during the entire life-cycle of OCS platforms, including design, development, construction, commissioning, maintenance, operations and salvage. The commenter noted that licensed professional engineers (PEs) are required by law to hold public safety paramount.

• *Response:* BSEE does not agree that the use of PEs should be required more often than already provided for in this final rule and the existing regulations. Several provisions of the final rule require PE certifications. For example, final § 250.428(b) requires certification by a PE for changes to casing setting depth or hole interval drilling depth and changes to the well program due to an inadequate cement job. There are also several provisions in the existing regulations (*e.g.,* § 250.420(a)(6)(i)) that require, or allow, the use of PEs and that are unchanged by this final rule. In addition, the requirements in this final rule for verifications and certifications by a BAVO or other independent third-party will help ensure that the safety and environmental protection purposes of this rule will be achieved without the need for additional requirements for use of PEs.

d. Requests for Shorter or Longer Compliance Periods

Summary of Comments: Some commenters observed that the proposed rule was published more than five years after the *Deepwater Horizon* incident. The commenters voiced support for the proposed effective date of 3 months following publication of the final rule for most of the proposed rule's requirements, since most, but not all, operators are already using equipment and procedures consistent with a majority of the proposed requirements. The commenters expressed concern with the proposal for longer compliance periods for several key requirements, including: 3 years for RTM; 5 years for shear rams on subsea BOPs and on surface BOPs on floating facilities; and 7 years for a mechanism coupled with each shear ram that centers drill pipe during shearing operations. One of the commenters noted it could be more than sixteen years after the *Deepwater Horizon* incident before BSEE finalizes and the industry implements critical components of offshore drilling safety. The commenters urged BSEE to shorten these compliance periods to enhance safety and environmental protection in an expeditious manner.

BSEE received other comments on the proposed rule, however, that raised concerns that the proposed compliance periods for certain provisions were too short. Those concerns included: Availability of required equipment; time needed to plan and install the equipment; and time needed to develop new or alternative equipment to meet the requirements.

• *Response:* BSEE agrees that it is extremely important to move ahead with these final rules to implement many of the recommendations from the *Deepwater Horizon* investigations and to help prevent catastrophic events from occurring again. BSEE considered a number of factors in identifying appropriate compliance periods for the various provisions in this rule, including information from public commenters on those requirements and information obtained, among other activities, from prior interactions with stakeholders, involvement in development of industry standards, and evaluation of current technology.

BSEE considered all of the comments regarding shortening and lengthening the compliance periods and determined that most of the proposed compliance periods were appropriate. BSEE did, however, determine that several requirements warranted longer compliance periods, as discussed in part III of this document. BSEE believes that compliance with these rules will improve well control, safety and environmental protection in a timely manner for the near and long term.

5. Contractor/Operator/Manufacturer Responsibilities

Summary of comments: Several commenters expressed uncertainty regarding potential responsibilities and liabilities of contractors and individuals performing regulated activities.

• *Response:* These final regulations do not alter BSEE's existing position and interpretations with respect to the parties responsible for complying with applicable regulations and related requirements. The lessee, operator (if one has been designated), and the person that actually performs an activity (which includes contractors) to which a particular provision of a regulation, lease, permit, or plan applies are jointly and severally responsible for complying with that provision. (*See* § 250.146(c).) Regulatory compliance is a fact-specific and context-specific matter, dependent upon that contractor's actual scope of activities and responsibilities (which is typically a matter of private contract with the lessee/operator), and is therefore not susceptible to general characterization. BSEE's responses to specific issues regarding responsibilities for compliance follow.

Summary of comments: Some commenters asserted that if contractors and individuals (along with lessees, operators, *et al.*) are jointly and severally responsible for compliance, proposed § 250.107(a)(4)—requiring lessees, holders of operating rights, designated operators and certain others to comply with all lease, plan, and permit terms and conditions—would implicitly require contractors and other individuals to ascertain all lease, plan, and permit terms and conditions, and potentially would make the contractor and individuals responsible for compliance with all such terms and conditions. The commenters asked if that is what BSEE intended.

• *Response:* Under existing § 250.146(c), the lessee, operator (if one has been designated), and the person actually performing an activity (including contractors or individuals) to which a particular regulation applies are jointly and severally (*i.e.,* equally) responsible for complying with that regulation. Therefore, actual performance of an activity is one of the triggers for the responsibility to comply with the associated requirements of lease, permit and plan terms and conditions of approvals. (*See, e.g.,* existing § 250.101(a).) Accordingly, under final § 250.107(a)(4), any person who actually performs an activity governed by a lease, permit or plan term or condition will also be responsible for compliance with that term or condition.

BSEE expects the person performing such an activity to be familiar with all terms and conditions relevant and applicable to the activity. However, contractors and other parties actually performing specific activities are not responsible for complying with lease, permit or plan terms or conditions that are outside the scope of activities that they actually perform. Thus, it is not necessary for such persons (contractors or individuals) to be familiar with terms or conditions of the lease, permit or plan that are not associated with activities that they actually perform.

Summary of comments: Some commenters asked whether, under proposed § 250.107(e)—regarding BSEE orders to ensure compliance with the part 250 regulations—BSEE would issue orders to shut-in operations to the ''lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s)'' and any person actually performing the activity.

• *Response:* BSEE has the legal authority under OCSLA and its implementing regulations to issue shut-in orders to the lessee, operator (if one has been designated), and the person (which includes contractors) actually performing an activity to which a particular regulation, lease, permit, or plan applies. Regardless of whether BSEE orders a contractor to shut-in operations, BSEE will typically issue such an order to the lessee or designated operator in such cases.

Summary of comments: Some commenters asked whether, under proposed § 250.428(d)—which pertains to certain cementing and casing situations—reports to the District Manager of immediate actions taken to ensure the safety of the crew or to prevent a well-control event, create an obligation for contractors to provide individual reports or to verify that such reports have been submitted by the operator.

• *Response:* As a general matter, BSEE looks to the designated operator to make filings on behalf of all lessees and owners of operating rights. More specifically, new § 250.428(d) describes actions a lessee (among others included in the definition of ''you'' in § 250.105) must take when remediating inadequate cement jobs. Because existing § 250.146(c) states that when a regulation requires that a lessee take an action, the person actually performing the activity is also responsible for complying with that requirement, it follows that the lessees' reporting duties under § 250.428(d) for immediate action to remediate inadequate cement jobs could extend to a contractor to the extent that contractor actually performs the activity.

Summary of comments: Some commenters asked BSEE to clarify who is ultimately responsible for the determination that a well has been secured, under proposed § 250.703(c), which requires continuous surveillance of the rig floor from the beginning of operations until the well is completed or abandoned unless the well has been secured.

- *Response:* Under § 250.146(c), the lessee, operator (if one has been designated), and the person actually performing the activity are jointly and severally responsible for complying with the regulation. If a contractor actually performs activities associated with securing a well, that contractor is responsible for complying with this regulation in performing those activities.

Summary of comments: Some commenters asked if, under proposed § 250.712, which discusses rig movement reporting requirements, BSEE expects rig movement reports to be made directly by a drilling contractor and if the drilling contractor will be held responsible for the report in the absence of reporting by the operator.

- *Response:* Under existing § 250.146(c) and final § 250.712, the lessee, operator (if one has been designated), and the person (including a contractor) actually performing the activity are jointly and severally responsible for complying with this rig movement reporting regulation. However, it does not follow that, even if a contractor actually moves the rig, the contractor must report the movement. When parties are jointly and severally responsible to comply with a requirement, any of the responsible parties could satisfy that requirement; in general, BSEE would expect the lessee or the operator to file such a report, although there may be circumstances in which it would be reasonable and prudent for the contractor who moved the rig to submit the report. In all cases, at least one of the responsible parties must fulfill the regulatory requirements.

Summary of comments: Some commenters asked whether, under proposed § 250.715(f)—which requires lessees, designated operators, holders of operating rights (and other entities specified in the § 250.105 definition of ''you'') to allow BSEE real-time access to MODU or jack-up location data—BSEE expects that a drilling contractor will directly provide BSEE with access to rig location data, and whether the drilling contractor will be held responsible for providing such access only in the absence of any action by the operator.

- *Response:* Final § 250.715(f) requires lessees, designated operators, holders of operating rights (and other entities specified in the existing § 250.105 definition of ''you'') to allow BSEE real-time access to MODU or jack-up location data. Under existing § 250.146(c) however, the lessee, operator (if one has been designated), and the person actually performing the activity (including a contractor) required by § 250.715(f) are jointly and severally responsible for providing BSEE with access to rig location data.

Summary of comments: A commenter asked whether, under proposed § 250.720 (securing of wells), a contractor would bear a residual responsibility/liability for downhole integrity of the well or the effectiveness of the well plugs.

- *Response:* Final § 250.720 specifies a number of well security procedures that must be followed before moving off the well. Some of those procedures are substantive and require physical activity (such as installing two independent barriers) and some are administrative (*e.g.,* seeking approval by the BSEE District Manager for installation of independent barriers). In some cases, certain activities under § 250.720 may be performed by a contractor or another person acting on behalf of the lessee or operator. In accordance with § 250.146(c), the lessee, designated operator, and the person actually performing any activity related to securing a well under § 250.720 are jointly and severally responsible for complying with the requirements of that section. It is not possible, however, to specify in advance how multi-party responsibility for compliance (and liability for noncompliance) with § 250.720 would be apportioned among lessees, operators, or other persons (including contractors) who perform any of the actions required by § 250.720 because responsibility would necessarily depend on fact-specific circumstances associated with each case. BSEE notes, however, that § 250.720 does not expressly require the installation of plugs or address the issue of ''residual responsibility'' for long-term integrity of the well; rather, it requires the installation of two independent barriers and approval by the District Manager of those barriers or of alternative procedures for securing the well if it is not possible to install the barriers.

Summary of comments: Some commenters asked whether there is an implicit requirement under proposed § 250.724, regarding RTM, for contractors or individuals who perform any of the actions required by § 250.724 to: Maintain duplicate records; and ascertain if the required real-time data gathering, monitoring, recordkeeping and transmission are being undertaken by the operator and, if they are not, to suspend operations.

- *Response:* As discussed in part V.B.4 of this document, the final RTM requirements in § 250.724 are somewhat different, based on other comments received, than the proposed requirements. However, although under existing § 250.146(c) and final § 250.724, the lessee, designated operator, and the person (including a contractor) actually performing the activity are jointly and severally responsible for complying with the final RTM requirements, neither the proposed nor final rule requires the contractor (or other person) to keep duplicate records. Nor does the final regulation require a contractor to determine whether a lessee or operator is otherwise gathering, recording, storing or transmitting required real-time data beyond the activities actually performed by the contractor or other person.

Summary of comments: Under proposed § 250.730(c)—regarding follow-up activities after a BOP equipment failure—a commenter asserted that a prudent drilling contractor would conduct such follow-up, especially since API Standard 53 covers follow-up activities. The commenter claimed that incorporation of that standard in the rule would make the standard's follow-up requirements mandatory. However, the commenter questioned whether a contractor would have a regulatory obligation to perform those follow-up activities. The commenter also asked what, if any, regulatory obligations are created for equipment manufacturers.

- *Response:* To the extent that a drilling contractor actually performs any BOP equipment follow-up activity required by final § 250.730(c), the contractor is jointly and severally responsible, along with the lessee and designated operator, for compliance with the specific requirement applicable to that activity. In particular, if the contractor performs any of the reporting or notification required by § 250.730(c), the contractor is responsible, along with the lessee and designated operator, for complying with the terms of the applicable requirement(s). If the contractor (or any other person) is not actually performing a required activity, but believes that a lessee, operator or other person may have failed to comply with any applicable requirement under BSEE's regulations, the contractor may report such noncompliance to BSEE in accordance with § 250.193.

Section 250.730(c) does not impose any requirements on OEMs.

Summary of comments: With regard to the proposed recordkeeping requirements in proposed §§ 250.740, 250.741, and 250.746, one commenter stated that, while a prudent drilling contractor presumably would maintain relevant records, such prudence differs from a regulatory obligation to do so. The commenter also asked whether BSEE's intends that these provisions create a regulatory requirement for contractors or individuals to maintain records duplicating those maintained by the operator.

- *Response:* To the degree that a contractor or any other person actually performs any of the recordkeeping activities required by §§ 250.740, 250.741, and 250.746, that person is jointly and severally responsible, with the lessee and designated operator (if any), for complying with the applicable requirements, including record retention, imposed by those sections. Those provisions of the final rule do not, however, require that the lessee, designated operator, or the person performing the recordkeeping requirements maintain duplicate copies of the records kept by other jointly responsible parties.

6. Economic Analysis Comments

a. Analysis Period Used in the Initial Regulatory Impact Analysis (RIA)

Summary of comments: BSEE received several comments suggesting that the analysis period used in the initial RIA [10] for the proposed rule was insufficient to fully assess the impacts of the rule on OCS operations. Commenters noted, in particular, that offshore developments and equipment have lifecycles of 20 to 30 years, making the 10-year analysis period used in the initial RIA insufficient for estimating the costs and benefits of the rule.

- *Response:* BSEE determined that that the 10-year analysis period used in the initial RIA is appropriate to maintain reasonable certainty of the estimates, given the uncertainties that exist beyond 10 years with regard to industry activities, technological change, and energy markets.

b. Issues Associated With the Economic Baseline

Summary of comments: BSEE received several comments on the initial RIA indicating that some of the costs assumed to be part of the baseline (and, therefore, not considered costs of the rule) are actually related to activities that either are not covered by current industry standards or are not in accordance with existing regulations. Specifically, commenters referred to costs related to requirements for activity reporting and recordkeeping, BOP system testing, autoshear/deadman/EDS systems, casing and cementing, maintenance and inspection, and redundant components for well control, among others, as examples of costs the analysis purportedly failed to consider because they were assumed to be part of the baseline.

- *Response:* BSEE established the baseline used in the initial (and the final) RIA in accordance with the guidance provided by Office of Management and Budget (OMB) Circular A–4 (''Regulatory Analysis''). This guidance states that the ''baseline should be a best assessment of the way the world would look absent the proposed action[,]'' i.e., without the implementation this final rule. (OMB Circular A–4 sec. E. 2. ''Developing a Baseline.'') Without this rule, BSEE's best assessment of the way the world would look includes compliance costs associated with current industry practices, existing regulations, DWOPs, NTLs, and industry standards. Therefore, based on the Circular A–4 guidance, BSEE has reasonably determined that the costs listed by the commenters are appropriately included in the baseline.

In contrast, many of the comments appeared to assume that any cost associated with requirements of this regulation is a cost of the rule regardless of whether that cost is already incurred based on current standard industry practice, existing regulations, or other indicators of state of the world in the absence of this rule. This assumption is inconsistent with both OMB guidance and with the general principles upon which an RIA is based. Additional discussion of BSEE's development of the baseline scenario can be found in Section 4 and in Appendix A of the final RIA for this rule, which is available in the regulatory docket at *www.regulations.gov* (enter BSEE–2015–0002).

c. Costs Related to Equivalent Circulating Density Information

Summary of comments: One comment on the initial RIA asserted that the requirement to include information on the ECD under proposed § 250.413 would take additional time by the drilling engineer and additional staff time to interface with BSEE personnel.

- *Response:* BSEE notes that this information is already included in the driller's report, which is an existing requirement, and thus there is no additional cost as a result of this requirement.

d. Costs Related to Wellhead Systems Information

Summary of comments: One comment stated that the additional information to be provided on wellhead systems under proposed § 250.414(j) would require operators to include wellhead and liner hanger specifications in the APD, resulting in an additional cost to operators.

- *Response:* This information is readily available from the OEM, once the operator purchases the wellheads, so the additional cost to operators due to these requirements should be minimal.

e. Tubing and Wellhead Equipment Costs

Summary of comments: Some comments asserted that BSEE failed to adequately consider costs associated with the requirements in proposed §§ 250.518 and 250.619 for complying with industry standards for tubing and wellhead equipment.

- *Response:* BSEE notes that these costs are included in the baseline since the only requirements in these sections that impose any costs are those associated with meeting the existing industry standard (*i.e.,* API spec. 11D1) for tubing and wellhead equipment that industry already follows.

f. Installation of Locking Devices

Summary of comments: Some comments suggested that BSEE had not included the cost of requiring the installation of hydraulically operated locks on surface BOP systems, under proposed § 250.733 (now covered under final § 250.735(g).)

- *Response:* Although the revised final rule will not require installation of hydraulically operated locks on surface BOP systems (as discussed in part VI.C),

[10] This document uses the terms ''initial RIA'' and ''initial economic analysis'' interchangeably. Both terms refer to the initial regulatory impact analysis performed for the proposed rule, as required by E.O. 12866, which is available in the regulatory docket for this rule at: *www.regulations.gov* (Enter BSEE–2015–0002).

BSEE agrees with the comment that the costs of installing hydraulic locks should have been included in the initial RIA. Under the revised final § 250.735(g), operators are not require to install hydraulic locks on surface BOPs. Instead, operators must install remotely-operated locks (which may but are not required to be hydraulic locks) on surface BOP blind shear rams and must install either manual or remotely-operated locks on surface BOP pipe rams or variable bore rams. Although not required to do so, operators may choose to comply with this revised requirement by installing hydraulic locks on some or all of these surface BOP sealing rams. Therefore, as one of the comments suggested, BSEE has added to the final economic analysis a one-time cost of $50,000 for each of the estimated 50 surface BOP rigs that could choose to install hydraulic locks this installation. Accordingly, the final RIA includes a one-time cost to industry of $2.5 million.

g. Capping Stack Test Costs

Summary of comments: Some comments suggested that BSEE underestimated the costs of capping stack tests in the initial RIA.

- *Response:* BSEE analyzed these comments and agrees that the cost estimate should be revised upward. Using information provided in one of the comments, BSEE revised the cost estimate (to industry overall) from $80,000 per year to $226,000 per year.

h. Costs related to Safe Drilling Margins

Summary of comments: Some comments suggested that the costs in the initial RIA should have included a higher cost for the requirement for safe drilling margins under proposed § 250.414. The proposed requirement specified that the static mud hole weight must be at least 0.5 ppg below the minimum of the lower of the estimated fracture gradient or the casing shoe pressure integrity test (the 0.5 ppg safe drilling margin).

- *Response:* This proposed requirement was revised in the final rule to allow for alternative drilling margins in situations where the operator provides justification and documentation in the APD that warrant variations, based on the specific well conditions, in order to maintain a level of safety equivalent to the 0.5 ppg requirement. Because the 0.5 ppg safe drilling margin is consistent with typical margins in approved APDs under current BSEE and industry practice, and the provision for approval of alternative margins is consistent with existing § 250.141, the costs associated with complying with these safe drilling margin requirements (other than minor administrative and recordkeeping costs) are part of the baseline.

Additionally, the commenters' estimated costs for complying with the proposed safe drilling margin requirements, based on the proposed language, would be significantly less under the final regulatory language, which provides operators with more flexibility to set lower drilling margins, upon providing adequate documentation with the APD submittal and receiving approval by BSEE.

i. RTM-Related Costs

Summary of comments: BSEE received several comments suggesting that the costs associated with RTM requirements for well operations were underestimated in the initial RIA.

- *Response*: These comments tended to assume greater demands on the RTM systems (such as the exchange of more information through RTM than was necessary, or the mandatory creation of new RTM centers) than the proposed rule actually intended. Further, BSEE has clarified and modified several aspects of the RTM requirements, and made them more performance-based, in the final rule. Although the performance-based requirements should make the RTM provisions less costly overall than the proposed requirements (since operators presumably will use the lowest cost means to achieve the performance goals), the final rule retains several of the proposed RTM requirements that were the basis of most of the RTM-related costs estimated in the initial RIA. (For example, the final rule still requires that operators gather and monitor RTM data, using an independent automated system, on the well's BOP control system, the fluid handling system, and downhole conditions.) After further review of its initial RIA, BSEE has concluded that the initial costs estimates for the proposed RTM requirements, as they were originally intended, are a reasonable and conservative upper bound on the potential costs of the final rule, and that the commenters' higher estimates were based on incorrect assumptions about the scope and intent of the proposed requirements. Accordingly, BSEE has retained the initial costs estimates for RTM in the final RIA. Further discussion of the cost estimates for the final RTM requirements are found in part VIII, ''Regulatory Planning and Review,'' and in the final RIA.

j. BAVO-Related Costs

Summary of comments: New paragraph (a) in final § 250.732 requires any organizations that want to become a BAVO to submit certain information. Some comments suggested that this imposes additional paperwork costs on industry.

- *Response*: BSEE agrees and the final RIA estimates that these costs will result in an increase of approximately $10,000 annually to industry, including BAVO applicants.

k. MIA Report Costs

Summary of comments: BSEE received a comment that included a substantially higher estimate of the cost to operators for submitting the MIA Report to BSEE.

- *Response*: BSEE notes that the commenter incorrectly calculated this cost on a per-well basis, instead of on a per-rig basis, which is how the cost will actually be accrued. Accordingly, we have made no change to the initial RIA cost estimate, which is included in the final RIA.

l. Surface BOP Stacks and Drilling Risers Costs

Summary of comments: BSEE received comments asserting that the estimated costs in the initial RIA associated with the dual bore drilling riser requirements for surface BOP stacks were incomplete. In particular, one comment asserted that the proposed requirement for dual bore risers would necessitate the replacement of several existing riser systems.

- *Response*: The dual bore riser requirements in final § 250.733(b)(2) are limited to facilities or BOPs that are installed after the effective date for those requirements. Thus, BSEE does not anticipate any additional replacement costs for current drilling risers.

m. Gas Bleed Line Requirement Costs

Summary of comments: Some comments suggested that BSEE underestimated the cost of the requirement involving the installation of a gas bleed line under proposed § 250.734(a)(15).

- *Response*: BSEE has revised this requirement in the final rule by clarifying that the gas bleed line must be installed below the upper annular (not below both annulars), and the final requirement thus costs less than the proposed requirement would have cost. Moreover, based on BSEE's most recent analysis, the vast majority of subsea BOPs already have a gas bleed line installed, and the ones that do not will require only very slight modification under the final rule. Thus, the final RIA estimates a lower cost of compliance for this provision of the final rule.

n. Costs of Accumulator System Requirements

Summary of comments: BSEE received comments on the proposed accumulator system requirements in the proposed rule at § 250.735, including estimates of industry costs to comply with these requirements. Many of the estimated costs in these comments exceeded the costs estimated by BSEE in the initial RIA.

- *Response*: The final regulatory text for this requirement has been changed to better align with API Standard 53, thereby reducing its cost to industry. The remaining costs to comply with this final requirement are now minimal, as described in the final RIA.

o. Costs Related To Testing of ROV Intervention Functions

Summary of comments: BSEE received a comment that the testing of ROV intervention functions under proposed § 250.737 would require additional operational time per well, thereby imposing an additional cost.

- *Response*: BSEE does not estimate that there will be any additional costs to operators in this regard since such testing is consistent with industry standards, and is thus within the baseline of the analysis.

p. Costs Related To Breakdown and Inspection of BOP System and Components

Summary of comments: Several commenters asserted that the requirement in proposed § 250.739 that operators break down the entire BOP system every 5 years for inspection, without the option to phase or stagger inspection, would cause rigs to be out of service for extended periods of time, at substantial opportunity costs to industry.

- *Response*: As described in detail in parts V.B.3 and VI.C of this document, BSEE has revised the requirement in § 250.739 of the final rule to allow for phased inspections over the course of 5 years. This change should eliminate the need for rigs to be brought out of service for extended periods of time, and thus reduces if not eliminates the opportunity costs of such inspections.

q. Indirect Economic Impacts of the Rule

Summary of comments: *Claimed indirect costs*—Some comments suggested that BSEE should consider additional impacts of the rule. For example, several comments asserted that the analysis did not appropriately account for broader ''indirect'' economic costs (such as costs arising out of job losses associated with reduced exploratory drilling activities) that commenters asserted may occur as a result of the rule. One of these comments also provided an economic analysis of the broad effects of the rule on the national economy.

- *Response*: BSEE does not agree that what the commenter has described as ''indirect costs'' of the rule are within the scope of the RIA as required by E.O. 12866. OMB Circular A–4 characterizes the indirect effects of a rulemaking as ''ancillary benefits and countervailing risks,'' but also states that these types of forecasted consequences, if highly speculative, may not be worth further formal analysis. Because there are a number of important and variable factors (unrelated to the implementation of the new regulations), such as the future price of oil, that will impact both the offshore oil and gas labor market and the marketplace for offshore oil and gas equipment and products, BSEE believes it is too speculative to predict whether this rulemaking will have the types of broad and indirect effects discussed by the comments. In addition, the indirect impacts expressed by the comments appear to be overstated or based upon certain assumptions for which there is no clear foundation.[11] Moreover, many of those estimated costs appear to be associated with requirements that are part of the economic baseline (*e.g.,* compliance with relevant provisions of API Standard 53); while others are associated with requirements discussed in the proposed rule that are not included in the final rule (*e.g.,* the proposed 1.5 times volume capacity accumulator requirement).

In addition, the commenters did not take into account the potential benefits to industry in terms of reduced costs of operation associated with implementation of the new regulations. For example, the reduction in costs attributable to the change in the BOP pressure testing frequency for workovers and decommissioning will exceed the costs that will result from the final rule.

The commenters also did not account for the indirect benefits from the rulemaking that may accrue to entities other than offshore operators. For example, the requirements for new equipment and for use of BAVOs may result in an increase in the offshore labor force, which should result in overall economic benefits. Although such indirect benefits may also be speculative, and thus do not warrant further analysis under OMB Circular A–4, their absence from the commenters' estimates means that their estimates do not present a complete picture of all of the potential indirect effects.

Summary of comments: *Costs to Contractors*—Several commenters asserted that BSEE did not adequately account for the additional costs to contractors that would result from the proposed rule.

- *Response*: BSEE disagrees with this comment because, in estimating costs, BSEE considered the costs of all of the equipment and labor services that would be needed to meet new requirements, regardless of how that equipment or labor is provided (whether by lessees, operators, or contractors).

Summary of comments: *Offshore support industries*—Commenters also stated that BSEE overlooked potential negative impacts to industries that support offshore oil and gas exploration and development.

- *Response*: BSEE disagrees with this comment. The economic analysis included in the initial RIA considered the costs of all of the equipment and labor services that would be needed to meet the new requirements. Many of the negative impacts projected by the commenters are speculative and outside the scope of the type of analysis required to support this rulemaking. (For example, one comment stated that the rule was ''unworkable as written and could effectively shut-down drilling operations . . . similar to another drilling moratorium.'') In addition, some commenters projected additional costs to industries that support offshore oil and gas exploration and development, but did not address whether there are potential benefits to other types of industries resulting from the new requirements. Thus, even assuming they were within the scope of this analysis, these comments do not present a complete picture of the potential impacts on other industries.

r. Impacts of the Regulation on National Energy Security

Summary of comments: BSEE received comments that the initial RIA did not account for the impacts of the proposed regulation on national energy security. These comments suggested that the rule would weaken national energy security by reducing domestic oil production and increasing reliance on foreign oil.

- *Response*: BSEE does not agree with this comment. The commenters' prediction about the weakening of national energy security is highly speculative and thus outside of the scope of the regulatory impact analysis

[11] For example, one comment assumed that the costs of the rule would lead to a 20 percent decrease in the number of floating units and over 30 percent decrease in fixed platforms, but provided no explanation for those assumptions.

required by E.O. 12866 and OMB Circular A–4. For example, these comments apparently assume that this rulemaking will cause a reduction in domestic oil production over some period of time. As previously discussed, the net economic effect of the final rule on the oil and gas industry should be positive (*i.e.,* the potential benefits exceed the potential costs), which does not support the assumption of a reduction in domestic oil production. Rather, future technological advancements and variable market factors (*e.g.,* the price of oil) unrelated to the requirements of this final rule, are more likely to affect the future domestic oil production.

7. Clarification of Maximum Anticipated Surface Pressure (MASP)

Summary of comments: Some commenters recommended that BSEE change the reference to MASP in specific sections throughout the rule (*e.g.,* proposed § 250.734(a), requiring that the working pressure rating of each BOP component exceed the applicable MASP) to ''maximum anticipated wellhead pressure'' (MAWHP). They asserted that there is no industry agreed-upon definition of MASP, but that MAWHP is defined in API Standard 53.

• *Response*: BSEE does not agree that the recommended change is necessary. The MASP must be identified for the specific operation, and for a subsea BOP, the MASP must be taken at the mudline, as explained in § 250.730(a). As a practical matter, for surface BOPs, the MASP is the same as the MAWHP; and for subsea BOPs, the MASP, when taken at the mudline, as required by § 250.730(a), is also the same as the MAWHP. BSEE does not agree that use of MASP will cause any confusion. BSEE's existing regulations (*e.g.,* former § 250.448(b)), have long used the term MASP, and BSEE does not believe that the industry will have any difficulty understanding the meaning and use of that term in this rule.

C. Section-By-Section Summary and Responses to Significant Comments on the Proposed Rule

This summary discusses every section of 30 CFR part 250 covered by the proposed rule and this final rulemaking; sections of the existing regulations that were not addressed in the proposed or final rule are not included in this summary. BSEE did not receive any substantive comments on numerous sections covered by the proposed rule; those sections are included in this final rule and are summarized here. BSEE received substantive comments on many other sections covered by the proposed rule, some of which have been included in this final rule without revision and some of which have been revised in the final rule. Those sections, and the relevant comments on those sections as well as BSEE's responses are summarized here.

Subpart A—General

What does this part do? (§ 250.102)

This section of the existing regulation provides information on where to find information about various OCS operations in 30 CFR part 250. BSEE proposed to add new information to this section so the public will know where they can find requirements for well operations and equipment in new subpart G. BSEE received no substantive comments on this provision of the proposed rule and has included the proposed language in the final rule without change.

What must I do to protect health, safety, property, and the environment? (§ 250.107)

This section of the existing regulation lays out performance-based and other requirement that operators must meet to protect safety, health, property and the environment and requires the use of BAST whenever practical. BSEE proposed several revisions to this existing regulation. BSEE proposed to revise paragraph (a) of this section to include performance-based requirements that operators utilize recognized engineering practices that reduce risks to the lowest level practicable during activities covered by the regulations and conduct all activities pursuant to the applicable lease, plan, or permit terms or conditions of approval. BSEE also proposed adding new paragraph (e) to clarify BSEE's authority to issue orders when necessary to protect health, safety, property, or the environment. BSEE received several comments on the proposed changes and additions to this section but, for the following reasons, has included the proposed language in the final rule without change.

Comments Related to Proposed § 250.107—Suggested Standards for Incorporation

Summary of comments: Commenters expressed several concerns about this section. One commenter focused on the performance-based intent of this section. The commenter recommended that BSEE incorporate by reference established and well known standards (International Electrotechnical Commission (IEC) 61508 and 61511)) to support the provisions. The commenter suggested that these standards, which are for developing safety instrument systems, including programmable systems (*i.e.,* software), to a target level of reliability, could be adapted to support the rule. The commenter suggested that the methodology in IEC 61508 and 61511 could be used to manage components and materials to ensure quality, so that reliability is not degraded and can be controlled via this process even if original parts are replaced by less expensive versions that have the same specification.

• *Response*: The international electrical standards referred to by the commenter (which apply broadly to electrical and electronic systems used to carry out safety functions and are not specifically related to well control systems) were not proposed for incorporation in the proposed rule and are outside the scope of this rulemaking. However, BSEE may evaluate those standards at a later date and, if BSEE determines that it is reasonable and appropriate to incorporate some parts or all of those standards, BSEE may propose to do so in another rulemaking.

Comments Related to Proposed § 250.107(a)—Definition of ''You''

Summary of comments: Some commenters asserted that proposed § 250.107(a)(4)—requiring lessees, designated operators, and other persons specified in the existing definition of ''you'' in § 250.105, to comply with all lease, plan and permit terms and conditions—creates an implicit requirement for contractors or individuals performing specific activities subject to the regulations to ascertain all lease, plan, and permit terms and conditions.

• *Response*: As discussed in part VI.B.5 of this document, compliance with § 250.107(a)(4) does not require a contractor or other individual performing specific activities required by the part 250 regulations to be knowledgeable about every term in a lease, permit or plan if those terms are unrelated to the specific activities performed by the contractor. However, because existing § 250.146(c) makes any person who actually performs an activity jointly and severally responsible for compliance with the applicable regulatory provision, such persons should be familiar with the terms and conditions of the lease, permit or plan that are relevant to that activity.

Comments Related to Proposed § 250.107(a)(3)—Concerns Related to BAST

Summary of comments: Multiple commenters asserted that the new language in proposed § 250.107(a)(3) would implicitly change the BAST provisions in former § 250.107(c). In particular, multiple comments focused on the requirement in proposed § 250.107(a)(3) that lessees, operators, and others defined as ''you'' by § 250.105 use ''recognized engineering practices'' to reduce risks to the lowest practicable level. These commenters noted that the term ''recognized engineering practices'' is not defined in the regulations and questioned what practices would be considered as ''recognized'' and where the recognized practices would be referenced. Commenters also questioned what would happen if arguably better engineering methods and practices are developed in the future, but are not yet generally ''recognized'' by industry.

• *Response*: It is unclear why the commenter believed the new requirements proposed in § 250.107(a)(3) would change the BAST provisions in § 250.107(c). The commenter may have assumed that the new requirement would supersede or be inconsistent with the requirement to use BAST whenever practical. However, § 250.107(a)(3) does not change the BAST requirement; in fact, the new requirement is intended to complement the BAST provision by establishing a risk-based goal (to reduce risks to the lowest practicable level), and a performance-based requirement that lessees/operators meet that goal by using recognized engineering practices, when conducting certain regulated activities (*i.e.,* design, fabrication, installation, operation, inspection, repair, and maintenance). Such risk reduction and performance-based approaches are used in other provisions of this final rule and other BSEE regulations.

Regarding the specific comments on ''recognized engineering practices,'' BSEE expects that those practices may be drawn, for example, from established codes, industry standards, published peer-reviewed technical reports or industry recommended practices, and similar documents applicable to relevant engineering activities. BSEE may issue additional guidance on such issues in the future, when and if specific circumstances warrant such guidance.

Comments Related to Proposed § 250.107(a)(3)—Suggestions for Alternative Approaches To Reducing Risks

Summary of comments: One commenter commended BSEE for proposing the general performance-based requirement in § 250.107(a)(3) to reduce risks to their lowest practicable levels. The commenter noted that regulators can play a role in defining and challenging companies' risk control measures, and that this active engagement with industry drives down risk. The commenter also asserted that many of the other requirements in the proposed rule are overly prescriptive. The commenter suggested that prescriptive requirements can lead to safety plateaus, instead of continual improvements, and that some of the standards referenced in the proposed rule may not always reflect current industry best practices and, thus, would not encourage innovation. The commenter stated that it would be better for BSEE's regulations to include provisions that adapt in real-time to industry best practices and innovations.

• *Response*: BSEE agrees with the commenter's suggestion that it is often appropriate to use performance-based requirements that set safety and environmental protection goals and encourage innovation and continual improvement in meeting those goals, and that new § 250.107(a)(3) is such a requirement. In addition, numerous other provisions in this final rule are also performance-based. As to the commenter's suggestion that there may be additional opportunities to include more performance-based measures (presumably in lieu of prescriptive requirements) in this rule, the commenter provided no specific alternatives for BSEE to consider. In any event, as explained elsewhere in this document, the final rule revises several provisions of the proposed rule, as suggested by other commenters, to make them less prescriptive and more performance-based (*e.g.,* the revised safe drilling margin provision in final § 250.414(c)). On the whole, BSEE believes that this final rule effectively combines prescriptive and performance-based measures, as appropriate, to ensure and improve well control and to prevent harm to persons and the environment.

Comments Related to Proposed § 250.107(e)—Concerns About BSEE-Issued Orders

Summary of comments: A commenter asked whether orders issued by BSEE under proposed § 250.107(e) (*e.g.,* to ensure compliance with 30 CFR part 250 regulations, or to prevent serious, irreparable or immediate harm, or to stop violations of the law) would be issued to both the ''lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s)'' and to any person actually performing the activity. Another commenter stated that the orders described in proposed § 250.107(e) are reactive methods for enforcing performance requirements, and that reactive methods are not enough to reduce risks to the lowest level.

• *Response*: Regarding the entities to whom BSEE may issue orders under new § 250.107(e), it would be premature and speculative for BSEE to identify in advance all of the parties to whom any specific order may be issued. Orders will be issued on a case-by-case basis as appropriate under the particular circumstances of each case. BSEE has legal authority to issue shut-in orders to lessees, operators (if designated) and any person (including contractors) who actually performs any activity to which a regulation or lease, plan or permit term applies. Whether or not BSEE orders a contractor to shut-in operations (suspension), BSEE typically also issues a corresponding order to the lessee or designated operator in these cases.

BSEE agrees with the comment stating that orders issued under this section could, at least in some cases, be 'reactive'' in nature, and that reactive measures alone may not be enough to reduce risks to the lowest level. However, any orders issued under § 250.107(e) would be only one of many measures established by this final rule, most of which set performance goals or prescribe specific measures to be taken in advance of any harm, to improve safety and environmental protection. BSEE has determined that orders authorized by paragraph (e) are an appropriate complement to those other measures to ensure that the regulations, as a whole, achieve their protective purpose.

Service Fees (§ 250.125)

The table in this section of the existing regulation lists fees that operators must pay to BSEE for certain services. BSEE proposed to revise this section to reflect the current citation for payment of the service fee relating to DWOPs. BSEE received no substantive comments on this provision of the proposed rule and has included the proposed language in the final rule without change.

Documents Incorporated by Reference (§ 250.198)

This section of the existing regulation includes citations and other information regarding all documents (*e.g.,* industry standards) incorporated by reference in 30 CFR part 250, including where to find references to the incorporated documents in specific sections of the regulations. This section also discusses BSEE's process for incorporating documents by reference, the regulatory effects of incorporation, and procedures that operators may follow to seek BSEE's approval to comply with alternatives to an incorporated document. BSEE proposed revising this section to add references to the standards to be incorporated by reference in subpart G. BSEE received several comments on the proposed additions to § 250.198. BSEE considered those comments and, for the following reasons, has retained the proposed language, without change, in the final rule.

Comments Related to Proposed § 250.198—Technical Support Documents

Summary of comments: A commenter requested that BSEE publish ''technical support documents'' summarizing its work in reviewing each standard that it proposed to incorporate by reference in this rule, including a determination that each standard is BAST.

- *Response*: All of the documents proposed to be incorporated by reference in this rulemaking were and are available for public review. The National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113) requires that BSEE rely on voluntary consensus standards where practical, Public Law 104–113, section 12(d). BSEE reliance on these standards is principally achieved through incorporation by reference of industry standards into the bureau's regulations. It is unclear what ''technical support documents'' the commenter is referring to, but the NTTAA does not require an agency to publish its underlying deliberations on why it is appropriate to incorporate by reference a specific standard. BSEE has explained its reasons for incorporating the standards referenced in this rulemaking in both the proposed rule and this preamble.

In addition, BSEE does not make a BAST determination in connection with the incorporation of industry standards. BSEE's authority under the NTTAA to incorporate industry standards into BSEE regulations is separate from the authority to require BAST under OCSLA. The NTTAA mandates that Federal agencies use technical standards developed or adopted by voluntary consensus standards bodies, as opposed to using government-unique standards, when practical. BSEE follows the requirements of the NTTAA and of OMB Circular A–119 when incorporating standards into the regulations. These are not tied to the BAST concepts derived from OCSLA or its implementing regulations.

Comments Related to Proposed § 250.198—Concerns About the Incorporation of Earlier Editions of Standards

Summary of comments: A number of commenters noted that some of the standards proposed for incorporation by reference in this rule do not reflect the current editions of those standards. Commenters requested that BSEE update those standards to the current editions when incorporated in the final rule. Commenters stated that the updated standards reflect the latest knowledge and experience of industry experts resulting from a collaborative review of the standards. They also stated that older editions of some standards are no longer available, and that incorporation of older editions may create confusion. Commenters suggested that, to resolve the issue of keeping incorporated standards up to date, BSEE should remove references to specific editions of the standards and add language to the regulations that refers to the ''most current edition'' of a standard.

- *Response:* BSEE recognizes the concern related to incorporating the most current edition of each standard. BSEE reviews all standards incorporated by reference to ensure they are appropriate and technically sound. BSEE can choose to keep a certain edition in the regulations even if there is an updated edition (*e.g.,* if BSEE does not agree with the technical changes or options allowed in a newer edition of an industry standard). This is done on a case-by-case basis for each standard. The change to a new edition, or removal of a discontinued standard, is not automatic and requires rulemaking. (In some cases, BSEE may use a direct final rule to incorporate new editions of standards already incorporated, if the new edition meets the requirements of § 250.198(a)(2)). BSEE is actively reviewing new editions of many standards, although newer editions are constantly in development.

Moreover, BSEE is prohibited, under applicable rules governing incorporation by reference, from automatically incorporating future amendments to or editions of a standard. (*See* 1 CFR 51.2(f); 30 CFR 250.198(a)(1).) However, operators may comply with a later edition of a standard incorporated in BSEE regulations if the operator demonstrates that compliance with the newer edition is at least as protective as the incorporated edition, and if BSEE approves the alternative compliance. (*See* 30 CFR 250.198(c).) Operators can also continue to use older standards, other than those incorporated by reference, if they can demonstrate an equivalent level of safety and environmental protection, pursuant to § 250.141.

Comments Related to Proposed § 250.198—Effective Dates of Standards

Summary of comments: Other commenters requested that, for standards applicable to equipment requirements under this rule, BSEE add provisions that allow the operator to use the standard that was in effect at the date the specific equipment was manufactured. This would prevent existing equipment and facilities that were manufactured and accepted under previous standards from being rendered obsolete by regulations incorporating newer standards. One commenter noted that BSEE is taking that approach with another rulemaking; *i.e.,* proposed updating of the edition of API Spec. 2C for offshore pedestal-mounted cranes currently incorporated in § 250.108 (*see* 80 FR 34113 (June 15, 2015)). Commenters specifically cited the need to apply this approach to four standards proposed for incorporation in this rule: ANSI/API Spec. 16A, ANSI/API Spec. 16C, API Spec. 16D, and API RP 17H. However, another commenter recommended that BSEE require operators with existing equipment to comply with the latest industry standards contained in API Standard 53.

- *Response:* BSEE has addressed comments regarding the applicability of this rule's equipment requirements to existing equipment and facilities (*e.g.,* requests to ''grandfather'' in existing equipment and facilities) in part VI.B of this document. With respect to the suggestion that BSEE require compliance with the ''latest . . . standards'' referenced in API Standard 53, BSEE must follow the provisions of the NTTAA and the guidelines issued by the OMB in Circular No. A–119 for incorporation of voluntary consensus standards. Under Circular No. A–119, the date of issuance of the standard being incorporated must be included in the regulation. Similarly, existing § 250.198(a)(1) requires that an incorporation by reference is limited to a specific edition of the incorporated document and does not include future revisions to that document. Thus, BSEE may not simply incorporate ''the latest edition'' of any standard, as suggested by the commenter. However, as previously explained, BSEE may approve compliance with a later (or an earlier) edition of an incorporated standard if an operator requests and justifies such an alternative under § 250.198(c) or § 250.141.

For the same reason, BSEE does not agree with the commenters' suggestion that the rules allow an operator to use equipment that meets whatever ''standard was in effect at the date the specific equipment was manufactured.'' Under the NTTAA and implementing regulations, any equipment standard that BSEE incorporates by reference must be identified by date and edition number. However, BSEE has addressed the ''grandfathering'' issue for existing equipment in part VI.B.4 of this document. And, where applicable, BSEE may approve compliance with an earlier edition of an incorporated standard if an operator requests and justifies such an alternative under § 250.198(c) or § 250.141.

Comments Related to Proposed § 250.198—Normative References

Summary of comments: Several commenters suggested that BSEE should not directly incorporate normative references (second-tier documents) used in an incorporated standard (first-tier document), in particular, API Standard 53.[12] Those commenters supported the incorporation of API Standard 53 in its entirety, and asserted that the normative references contained in that standard would also implicitly apply. One commenter also stated that separately incorporating the normative references within API Standard 53 would confuse the operators. However, other commenters suggested that concerns related to applying the edition of an equipment standard in existence at the time the equipment was manufactured (as previously discussed) would be minimized if the normative references in those standards were not incorporated by reference in BSEE's regulations.

Commenters asked if it was BSEE's intent to require the application of the normative references in API Standard 53 for purposes other than their relation to the provisions of API Standard 53 to be incorporated in the final rule. If so, they requested that BSEE should specifically state those other purposes in the final rule.

• *Response:* BSEE recognizes that compliance with a normative reference in an incorporated standard is implicitly necessary at times to ensure actual compliance with an incorporated standard. However, BSEE has decided to expressly incorporate the normative references within API Standard 53 (*i.e.,* relevant provisions of API Spec. 6A, API Spec. 16A, API Spec. 16C, API Spec. 16D, and API Spec. 17D), in the regulations (*see* final § 250.732(a)(2)) so that it is clear when compliance with those documents is required. This is also consistent with guidance from the Office of the Federal Register (OFR) related to the incorporation of second-tier documents. (*See* 78FR 60,784, 60,794–95 (Oct. 2, 2013).)

Comments Related to Proposed § 250.198—Additional Standards Documents Suggested for Incorporation

Summary of comments: Commenters suggested that in addition to updating the incorporation of API Spec. 6A, BSEE should also incorporate API Standard 6ACRA, First Edition, (June 2015) and API Spec 6A718, First Edition (March 2004), for completeness.

• *Response:* BSEE agrees that certain documents are more effective if incorporated with other associated documents. However, we did not include the suggested documents in the proposed rule, and BSEE has not yet determined whether those standards should be incorporated in the regulations. We may consider these documents for incorporation in the future using the evaluation process previously described. If BSEE decides to incorporate these documents, we will do so through a separate rulemaking.

Comments Related to Proposed § 250.198—Effective Dates of Documents

Summary of Comments: A commenter requested that we remove the effective dates from the citations of standards in § 250.198. The commenter suggested that the effective dates are of the monogram licenses, not for general industry use of the documents, and including the effective dates in the regulations could cause confusion. A commenter recommended that BSEE use the descriptions shown in the API Publications Catalog, which only include the standard number, title, publication date, and any errata/addenda.

• *Response:* BSEE disagrees. As previously stated, BSEE is required to include certain information from the standard, including the dates and editions of the incorporated documents, when incorporating documents by reference. (*See* § 250.198(a)(1); 1 CFR 51.9(b)(2).)

Comments Related to Proposed § 250.198—Availability of Incorporated Standards

Summary of comments: Two commenters asserted that BSEE acted illegally by not providing free, unrestricted, and online access to the standards incorporated by reference in the proposed rulemaking. The commenters asserted that BSEE had failed to make the incorporated materials reasonably available to the public, to discuss in the proposed rule preamble how it worked to make those materials reasonably available to interested parties, and to summarize in the preamble the material it proposed to incorporate, and thus that BSEE had violated the OFR regulations at 1 CFR 51.5(a). The commenters further asserted that, by failing to provide access to the incorporated standards, the proposed rule violated the APA because the proposed rule did not include ''either the terms or substance of the proposed rule or a description of the subjects or issues involved.'' (*See* 5 U.S.C. 553(a).) The commenters recommended that BSEE re-publish the proposed rule, with the standards available freely online.

The commenters also asserted various technical obstacles to purchasing the standards (both for print and online) from API and to viewing them in person at BSEE's offices. The commenters also raised numerous objections to the manner in which API presents the documents online, including technical hurdles for visually impaired people to view the standards online. The commenters also asserted that BSEE is in violation of the Rehabilitation Act of 1973 because visually impaired individuals are not able to view the standards properly on API's Web site. They also asserted that there is no guarantee by BSEE that the currently free online access for viewing the standards on API's Web site will last. Another commenter requested that, if BSEE cannot make the documents available to the general public, BSEE should, at a minimum, grant access to certain types of organizations (*e.g.,* local governments).

• *Response:* These comments do not address the substantive merits of the proposed rule. Rather, the comments principally focus on legal criteria relevant to BSEE's incorporation by reference of various industry standards.

Many of the detailed assertions in the comments (*e.g.,* complaints about API's Web site advertisements) are outside the scope of this rulemaking as well as unrelated to BSEE's compliance with applicable regulations for incorporating documents by reference, and thus do not require any further response.

In determining which industry standards to incorporate by reference into its regulations, BSEE has carefully evaluated potentially relevant standards, considered input from

[12] ''Normative references'' are typically other documents incorporated by reference within a standard that are considered necessary for compliance with specific parts of the ''first-tier'' standard.

various interested stakeholders, and proposed for incorporation those standards that BSEE determined, in its judgment, would reasonably serve the safety and environmental protection purposes of its regulations. In developing this final rule, BSEE also considered public comments on the proposed rule regarding which standards would best serve those purposes, as discussed elsewhere in this document. In doing so, BSEE has also complied with the mandate of the NTTAA (previously discussed) to make use, where appropriate and practical, of existing consensus standards in lieu of developing new government regulatory standards.

Moreover, BSEE disagrees with the commenters' claims that BSEE failed to discuss the actions it took to ensure that the materials incorporated in these rules were, and will be, reasonably available or to actually make the materials reasonably available. In proposing certain standards for incorporation in the final rule, and finalizing such incorporations in this final rule, BSEE has followed the requirements and procedures for incorporation by reference set out in OFR's regulations. (*See* 1 CFR part 51.)

In order to be eligible for incorporation by reference, a document must be ''reasonably available'' to affected persons (1 CFR 51.5, 51.7(a)(3)) and the notice of proposed rulemaking must discuss how the incorporated document is reasonably available to interested parties or how the agency worked to make those documents reasonably available. (*See id.* at § 51.5(a)(1).) The notice of final rulemaking must also discuss the ways that the incorporated document is reasonably available to, and how it can be obtained by, interested parties. (*See id.* at § 51.5(b)(2).)

The primary regulated community for these regulations is the offshore oil and gas industry, for which the costs for purchasing a copy of the industry standards (if they choose to do so) incorporated by reference in this final rule are not unreasonable. For other members of the public (including other government entities), BSEE discussed in the preamble to the proposed rule (see 80 FR 21506), and in this document (under ''Availability of Incorporated Documents for Public Viewing''), the reasonable methods by which the standards incorporated here may be reviewed, inspected, copied, or purchased.

In brief, BSEE explained in both documents how any member of the public may review the referenced standards for free on API's Web site or in person at BSEE's offices in Sterling, VA, or at NARA's offices in Washington, DC. These actions are consistent with BSEE's prior rulemakings incorporating many other standards in the part 250 regulations. Moreover, BSEE received informal approval from OFR for the proposed incorporations by reference in the proposed rule, and formal approval for the final incorporations in this final rule, in accordance with OFR's regulations (1 CFR 51.3 and 51.5), which include the requirement for making the documents reasonably available.

Similarly, we disagree with the commenters' claim that the proposed rule violated the APA by failing to adequately describe the materials proposed for incorporation. To the contrary, the proposed rule adequately described the referenced standards (*see* 80 FR 21506–21508), as does this document. In addition, OFR's informal approval of the proposed incorporations, and its formal approval of the incorporations in this final rule, means that OFR agrees that BSEE has met the requirement in the OFR regulations for describing the incorporated materials. (*See* 1 CFR 51.5(a)(2) and (b)(3).)

In addition, contrary to commenters' claims that BSEE must provide free, downloadable copies of the standards on its Web site, notwithstanding API's copyright claims to those standards, OFR has expressly concluded that an agency's incorporation by reference of copyrighted material does not result in the loss of that copyright.[13] OFR reached this conclusion based in part on its analysis of the decision in *Veeck* v. *Southern Building Code Congress International, Inc.,* 293 F.3d 791 (5th Cir. 2002). In the preamble to its recently promulgated amendments to the rules for incorporation by reference, OFR stated:

> that recent developments in Federal law, including the *Veeck* decision and the amendments to the Freedom of Information Act (FOIA), and the NTTAA have not eliminated the availability of copyright protection for privately developed codes and standards referenced in or incorporated into Federal regulations. Therefore, we agreed with commenters who said that when the Federal government references copyrighted works, those works should not lose their copyright.

(*See* 79 FR 66273.)

[13] Contrary to some commenters' claims, OFR's regulations also do not require BSEE to provide free, downloadable copies of the incorporated documents online, whether or not they are copyrighted. OFR expressly rejected that suggestion in its recent document promulgating the current regulations governing incorporation by reference. (*See* 79 FR 66267 (Nov. 7, 2014).)

Under the OFR regulations, BSEE is permitted to incorporate copyrighted materials into its regulations. Implicit within that permission is the fact that access to and presentation of certain incorporated standards is controlled principally by the third-party copyright holder. While BSEE works diligently to maximize the accessibility of incorporated documents, and offers direction to where the materials are reasonably available, it also must ultimately respect the publisher's copyright. Accordingly, issues related to how API structures its Web site or formats its copyrighted materials offered for free access are outside of BSEE's control and beyond the scope of this rulemaking.

Paperwork Reduction Act Statements—Information Collection (§ 250.199)

This section of the existing regulation provides the OMB control numbers associated with information collections under each subpart of part 250, and generally provides BSEE's reasons for collecting the information and explains how the information is used. BSEE proposed to revise this section by updating the OMB control numbers, by rewording some of the explanations for BSEE's information collections, and by adding references to proposed new information collections. After considering comments submitted on this section, BSEE has included the proposed language in the final rule without significant revisions. However, in response to certain comments, BSEE has revised the estimated burden hours for compliance with some of the information collections in the final rule, as explained in the following responses.

Comments Related to § 250.199—General Requirements for Well Operations and Equipment

Summary of comments: Several commenters raised concerns that additional time would be needed to account for requests for departures from operating requirements, as provided in § 250.702, and for requests for approval to use new or alternative procedures or equipment during operations, as provided in § 250.701. For example, some commenters asserted that the proposed requirement for use of subsea BOPs with ''dual-pod control systems'' and kelly valves will lead to requests for departures and for alternative procedures. The commenter explained that such requests would be likely because API Standard 53 requires subsea stacks to ''have fully redundant control pods'' and because kelly valves are no longer in widespread use in offshore drilling operations.

• *Response:* As discussed later in this part of the document, we have revised the requirement for subsea BOPs with ''dual-pod control systems'' to require only a ''redundant pod control system.'' This change will align the pod requirement in the regulations with the language of API Standard 53. BSEE agrees with the comment about the limited availability of kelly valves and has revised final § 250.736(d)(1) by replacing the references to kelly valves with ''applicable [k]elly-type valves'' as described in API Standard 53. Regardless, BSEE does not agree with the commenters' assertions regarding increased paperwork burdens. Ultimately, the requests for alternate procedures or equipment and requests for departures referenced in §§ 250.701 and 250.702 are voluntary submissions made pursuant to longstanding regulations found at §§ 250.141 and 250.142, and thus do not reflect a new paperwork burden under this rule.

Comments Related to § 250.199—APDs

Summary of comments: Several comments requested that we include additional burden hours to prepare required permitting information. One commenter stated that the dual riser requirement in proposed § 250.733(b) may require additional engineering time to assure existing floating production facilities have the room to accept dual bore risers or dual shear ram BOPs. Another commenter stated that, to meet the requirements in § 250.734(c) for drilling out the surface casing in a new well with a subsea BOP, additional burden hours would be needed to submit a revised APD, including the required third-party verifications, and to obtain BSEE's approval.

One commenter stated that § 250.418(g) of the proposed rule would likely require additional engineering time to develop a well abandonment plan that includes wash out or cement displacement to facilitate casing removal upon well abandonment. Another commenter stated that an additional man-day per individual well would be needed to provide a description of the source control and containment capabilities and receive APD approval pursuant to § 250.462(c).

We also received a comment requesting that we increase the estimated burden hours given that additional drilling prognosis information in the APD may be required by the District Manager under § 250.414(k).

• *Response:* BSEE agrees with several of the commenters' assertions and has increased the burden estimate for preparing APDs and APMs to comply with this final rule as described in part VIII (*Paperwork Reduction Act (PRA) of 1995*).

Comments Related to § 250.199—Tubing and Wellhead Equipment

Summary of comments: One commenter asserted that it may not be possible to set a packer deep enough to have a column of kill weight fluid at the packer. As a result, additional engineering time would be required to comply with the § 250.518(e) requirement for tubing and wellhead equipment for completion operations to determine if the casing design is suitable.

• *Response:* BSEE agrees with the comment and has increased the burden for APMs to account for the descriptions and calculations of packer depths required by this rule.

Comments Related to § 250.199—Well Operations

Summary of comments: We received numerous comments on the § 250.724(b) proposed RTM requirements. Commenters stated that such monitoring on all well operations, including shallow water shelf operations, would result in significant additions to the sensor, data integration, data telemetry band width, data reception and storage, and data monitoring and interpretation burden for all operators. They also expressed concern about how to comply with the new requirements to conduct continuous RTM of the BOP control system, the well's fluid handling systems on the rig, and the well's downhole conditions with the bottom hole assembly tools, and provisions for storage of the data.

• *Response:* BSEE agrees with the comment and has increased the burden hours to account for the development and implementation of an RTM plan, as required by the final rule, that includes all data required by § 250.724.

Comments Related to § 250.199—BOP System Requirements

Summary of comments: We received comments claiming that additional engineering time would be necessary to comply with the requirements of § 250.730(d). Since § 250.730(d) requires that any BOP stack manufactured after the effective date of the regulation comply with API Spec. Q1, the commenter stated that additional burden hours will be needed to design a BOP stack that complies with API Spec. Q1.

In addition, several commenters stated that there is an additional burden involved with submittals of an MIA Report as required by § 250.732(d) for a subsea BOP, a BOP used in an HPHT environment, or a surface BOP used on a floating facility. Specifically, they asserted that BSEE failed to account for the burden of obtaining BAVO certification of the MIA Report, as required by proposed § 250.731(f).

• *Response:* BSEE does not agree that any additional burden hours should be added for compliance with § 250.730(d). That provision does not create any new information collection burdens since it requires compliance with existing industry standards, the costs of which are included in the economic baseline.

However, BSEE has increased the burden hours for requesting approval to use new or alternative procedures, along with supporting documentation if applicable under § 250.730, should an operator seek to deviate from the requirements of § 250.730(d). BSEE has also increased the burden hours for complying with the § 250.731(f) MIA Report certification requirement.

Subpart B—Plans and Information

What must the DWOP contain? (§ 250.292)

This section of the existing regulation specifies information (e.g., description of the typical wellbore, structural design for each surface system) that must be included in a DWOP. BSEE proposed no changes to existing paragraphs (a) through (o) of § 250.292, and the final rule makes no changes to those paragraphs. BSEE proposed to add a new paragraph (p) to this section and to redesignate existing paragraph (p) as paragraph (q). Proposed new paragraph (p) specified information that must be included in the DWOP if the operator proposes to use a pipeline FSHR meeting certain conditions. This information is used in planning for production development. BSEE received several comments on this proposed addition, and for the following reasons, has included proposed paragraph (p) in the final rule with one revision to the proposed language, as described in the following response and in part V.C of this document. Former paragraph (p) is also included in the final rule, without change, as new paragraph (q).

Comments Related to § 250.292(p)—Pipeline Freestanding Hybrid Risers (FSHRs)

Summary of comments: Commenters suggested that BSEE apply § 250.292(p) only to permanent FSHRs, and not to risers used for exploratory wells or for source control and containment. Those commenters noted that exploration wells are not covered under the existing DWOP regulations (§§ 250.286 through

250.295), which apply to deepwater development projects, and that risers used for source control and containment are not part of a permanent installation.

• *Response:* BSEE agrees that this requirement applies only to permanent FSHRs for development projects under a DWOP. It is incorporated into a regulation setting forth requirements for the contents of a DWOP. Accordingly, it is inapplicable to operations that do not require a DWOP. BSEE would permit temporary FSHRs, such as those used with containment systems to respond to an emergency, on a case-by-case basis. BSEE has revised this paragraph in the final rule to clarify that it applies only to FSHRs ''on a permanent installation.''

Subpart D—Oil and Gas Drilling Operations General Requirements (§ 250.400)

This section of the existing regulation was entitled ''Who is subject to the requirements of this subpart?'' BSEE proposed to revise, this entire section, including the section heading, to require that drilling operations be done in a safe 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), the National security or defense, or the marine, coastal, or human environment. BSEE also proposed to clarify that, for drilling operations, the operator must follow the requirements of this subpart and the applicable requirements of proposed subpart G. BSEE received no substantive comments on this proposed provision and made no changes to the proposed language, which is now included in the final rule.

What must I do to keep wells under control? (§ 250.401)

BSEE proposed to remove and reserve this section of the existing regulation and to move the content of this former section to proposed § 250.703. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

When and how must I secure a well? (§ 250.402)

BSEE proposed to remove and reserve this section of the existing regulation and to move the content of this former section to proposed § 250.720. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

What drilling unit movements must I report? (§ 250.403)

BSEE proposed to remove and reserve this section of the existing regulation and to move the content of this existing regulation to proposed § 250.712. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

What additional safety measures must I take when I conduct drilling operations on a platform that has producing wells or has other hydrocarbon flow? (§ 250.406)

BSEE proposed to remove and reserve this section of the existing regulation and to move the content of this former section to proposed § 250.723. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

What information must I submit with my application? (§ 250.411)

This section of the existing regulation specified certain information that must be included in an APD, including descriptions of ''diverter and BOP systems.'' BSEE proposed to slightly revise this section to separate the requirements for diverter and BOP descriptions, and to updates the cross-reference in the section to include new subpart G. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language, which is included in the final rule.

What must my description of well drilling design criteria address? (§ 250.413)

This section of the existing regulation specifies the type of information that must be provided in the well drilling description portion of an APD. BSEE did not propose any changes to paragraphs (a) through (f) of the former § 250.413, which are retained unchanged. BSEE proposed to revise former paragraph (g) to require that the maximum ECD be included on the pore pressure/fracture gradient plot in the APD. BSEE received multiple comments on the proposed changes to paragraph (g) and, for the following reasons, has decided to revise the proposed language to require that the ''planned safe drilling margin,'' instead of the ECD, be included on the pore pressure/fracture gradient plot under the final rule.

Comments Related to Proposed § 250.413(g)—Well Drilling Design Criteria

Summary of comments: Multiple commenters had concerns regarding the requirement in proposed § 250.413(g) that well drilling design criteria include a plot showing maximum ECD. They stated that operators need to manage and adjust ECD during real-time operations, and thus no margin between ECD and fracture pressure or safety margin should be required to be specified in advance as part of the APD. The commenters also suggested that, since the intended use of the ECD cannot be specified in advance, it should be deleted from § 250.413(g).

• *Response:* BSEE agrees with the commenters that, since ECD may need to be adjusted during operations, BSEE would need to provide more clarification about how to determine maximum ECD in order for operators to include it within the plots. Therefore, BSEE removed the reference to ECD from final § 250.413(g) and inserted in its place a requirement to plot the planned safe drilling margin, as required to be included in the APD by final § 250.414(c). This planned safe drilling margin is based in part on the planned ECD and thus will provide information essentially equivalent to what inclusion of the maximum ECD would have provided.

What must my drilling prognosis include? (§ 250.414)

This section of the existing regulation describes the information that must be included in the drilling prognosis portion of an APD. BSEE did not propose any changes to paragraphs (a) and (b), and paragraphs (d) through (g), of the existing regulation and they have been retained unchanged. BSEE proposed to revise paragraphs (c), (h), and (i) of the existing regulation and to add new paragraphs (j) and (k) to § 250.414. Specifically, BSEE proposed: To revise paragraph (c) to better define the safe drilling margin requirements; clarify paragraphs (h) and (i) with minor wording changes; to add a new paragraph (j) requiring that the drilling prognosis include both the type of wellhead and liner hanger systems to be installed and a descriptive schematic; and to add a new paragraph (k) requiring submittal of any additional information required by the District Manager as needed to clarify or evaluate the drilling prognosis. BSEE received some comments on proposed paragraph (j), but has included that paragraph in the final rule without change. BSEE received many comments on the proposed changes to paragraph (c) and on proposed paragraph (k). After considering the comments, and for the reasons stated in the following responses to those comments, BSEE has revised the language of proposed paragraphs (c) and (k) and included that revised language in the final rule.

Comments Related to Proposed § 250.414(c)—Safe Drilling Margin

Summary of comments: BSEE received extensive comments on the proposed requirements in § 250.414(c) regarding safe drilling margins. The majority of these comments stated that the proposed 0.5 ppg safe drilling margin would pose operational problems, reduce the safety of drilling operations, and lead to unintended consequences. Commenters provided examples of concerns, such as limiting the selection of drilling fluids; potentially requiring more casing strings or smaller production casing sizes; economic hardships due to not being able to reach reservoirs by setting more casing; decreased production from the smaller hole sizes; and undue burden of submittals for alternative compliance. Recommendations to revise proposed § 250.414(c) included performance of a risk assessment and calculations to establish safe drilling margins for each well and for each drilling interval within the well.

BSEE also received comments on the proposed § 250.414(c)(3) requirements related to the ECD. Some commenters interpreted this proposed language to mean that drilling must stop when any lost circulation occurs. Clarifying language was recommended as follows: ''if lost circulation occurs, then the losses should be mitigated, and/or ECD managed to reduce the effects of lost circulation as per API Bulletin 92L.''

We also received a comment on the proposed requirements in § 250.414(c) for determining pore pressure and lowest estimated fracture gradients for specific intervals. The commenter emphasized that the purpose for this paragraph is to address planning (prognosis) for drilling operations and that it should not apply to the actual operations. The commenter recommended the following language: ''during planning for a specific interval, the relevant available offset hole behavior observations must be considered.''

- Response: BSEE agrees with a majority of the comments on § 250.414(c) and has not included proposed paragraph (c)(3) in the final rule (and renumbered proposed paragraph (c)(4) as paragraph (c)(3) in the final rule). BSEE otherwise revised paragraph (c) in the final rule to require a planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and based on a risk assessment consistent with expected well conditions and operations. Final paragraph (c) also requires that the safe drilling margin include use of equivalent downhole mud weight that is (i) greater than the estimated pore pressure, and (ii) except as provided in paragraph (c)(2), a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient. Final paragraph (c)(2) now clarifies that, in lieu of meeting the criteria in paragraph (c)(1)(ii), operators may use an equivalent downhole mud weight as specified in the applicable APD, provided that the operators submits adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight. Finally, paragraph (c)(3) states that, when determining the pore pressure and lowest estimated fracture gradient for a specific interval, the operator must consider related off-set well behavior observations.

Although 0.5 ppg is typically an appropriate safe drilling margin for normal drilling scenarios, BSEE understands there are circumstances where a lower drilling margin may be acceptable to drill a well safely. The revisions made in the final rule better define safe drilling margins, requiring the 0.5 ppg margin under most circumstances, but providing operators with the flexibility to use a lower safe drilling margin when appropriate.

The changes in the final rule will alleviate, if not eliminate, much of industry's operational and economic concerns with the proposed 0.5 ppg margin, including industry's concern that a 0.5 ppg drilling margin—with no exceptions—would effectively preclude the continued use of dynamic pressure drilling and inhibit development of new technology.

By requiring justification for, and prior approval by BSEE of, any alternative to the 0.5 ppg margin, these revisions will provide BSEE with the information needed to make appropriate case-by-case decisions on specific drilling margins. BSEE could also use this option to identify and focus its resources on the potentially higher risk well sections where the safe drilling margin may be of greater concern. These revisions will increase planning flexibility for operators when drilling into areas that could require lower safe drilling margins, such as depleted sands or below salt (common occurrences in the GOMR). Industry will be able to determine and use (subject to BSEE approval) appropriate mud properties (density, viscosity, additives, etc.) best suited for a specific well interval based on drilling and geological parameters.

The final rule also revised the proposed language to refer to ''off-set well''—instead of ''hole''—conditions; the final rule language will better align the regulatory language with industry terminology and clarify BSEE's intent. For a more in-depth discussion of the changes to final § 250.414(c), refer to part V.B.1 of this document.

Comments Related to Proposed § 250.414(j)—Wellhead System and Liner Hanger System

Summary of comments: BSEE received comments on the proposed § 250.414(j) requirements related to wellhead system and liner hanger system information. Commenters stated that operators will not have access to machine drawings for equipment purchased from manufacturers since this is considered proprietary data. A commenter recommended that the word ''descriptive'' be changed to ''detailed'' and that BSEE allow documentation that is available to the operator to be provided to BSEE.

- *Response:* BSEE disagrees with these comments and has made no changes to § 250.414(j) in the final rule. BSEE is aware that operators typically receive schematics from the manufacturers, and those schematics are sufficient to meet the requirements for describing the wellhead and liner hanger systems. In addition, it is unclear from the comment why a change from ''descriptive'' to ''detailed'' would better classify the type of schematics available.

Comments Related to Proposed § 250.414(k)—Additional Information

Summary of comments: BSEE received comments on the proposed § 250.414(k) requirement to provide any additional information required by the District Manager. Commenters stated that this section should be restricted to necessary information that can be reasonably supplied by the operator. Commenters also suggested that the District Manager should provide justification to the operator for the requested additional information.

- *Response:* The District Manager may require additional information on the drilling prognosis on a case-by-case basis, based on unique site or well conditions. The District Managers would, of course, take into account the potential need for such information to protect personnel or the environment, given the purposes of these regulations. Like many similar provisions throughout part 250, § 250.414(k) is intended to give District Managers the necessary flexibility and discretion to require information as needed in specific cases to fulfill the purposes of the regulation. Nonetheless, BSEE has slightly revised paragraph (k) in the final rule to confirm that the District Manager may require additional information needed to clarify or evaluate the drilling prognosis submitted under this section.

What must my casing and cementing programs include? (§ 250.415)

This section of the existing regulation describes the information on casing and cementing programs that must be included in an APD. BSEE proposed no changes to paragraphs (b) through (f) of this section, which have been retained unchanged in the final rule. BSEE proposed to revise former paragraph (a) of this section to require casing information for all sections of each casing interval. BSEE proposed that operators must include bit depths (including measured and true vertical depth (TVD)) and locations of any installed rupture disks, and indicate either the collapse or burst ratings, in their APDs. Requiring this information for all sections for each casing interval will make well design calculations and APD submittals more accurate and provide a more complete representation of the well. BSEE received one comment on the proposed § 250.415, and as discussed in the following response, has included proposed paragraph (a) in the final rule without change.

Comments Related to Proposed § 250.415—Quality Assurance

Summary of comments: One commenter suggested that we require a Quality Assurance/Quality Control (QA/QC) plan for cement installation and recommended that we add the QA/QC protocol to § 250.415 and require it for each well.

• *Response:* Section 250.420(a)(6) of the existing regulations already requires the casing and cementing design to include a certification signed by a registered PE. This verification of the casing and cementing design by a PE provides the necessary QA/QC. We have, therefore, made no changes to final § 250.415 based on the comment.

What must I include in the diverter description? (§ 250.416)

This section of the existing regulation specified the information that must be included in the descriptions of diverter systems and BOP systems contained in an APD. BSEE proposed to revise this section by removing former paragraphs (c) through (f), which required certain information for BOP system descriptions, which BSEE proposed to move to new §§ 250.703, 250.731 and 250.732, and by removing paragraph (g), which specified criteria for independent third-parties that verify certain BOP information. Under the proposed rule, § 250.416 would include only the former language, in paragraphs (a) and (b), regarding diverter descriptions and would be re-titled accordingly. Based on comments submitted on the proposed changes to this section, as explained in the following response, BSEE has included former paragraph (a) in the final rule without change, as proposed. BSEE also included former paragraph (b) in the final rule, with one minor change to the former paragraph (b)(1).

Comments Related to Proposed § 250.416—Descriptions of Diverter Systems

Summary of comments: One commenter was concerned that proposed § 250.416 did not actually require use of equipment and instrumentation to identify hydrocarbons that have travelled above the BOP and into the marine riser. The commenter stated that current rigs have zero riser instrumentation (for detecting/tracking hydrocarbons within the marine riser), and that they are equipped with a diverter system. The commenter suggested that we completely revise § 250.416(b) to require that diverters have riser instrumentation (such as ''distributed'' pressure gauges to measure differential pressures) that can confirm that the volume of gas does not exceed a certain limit and impose back-pressure to keep gas from coming out of solution.

• *Response:* BSEE does not agree with the suggestion that we should transform proposed § 250.416 from an informational provision (*i.e.,* requiring a description of the diverter system) into a substantive equipment provision requiring specific instrumentation. Although BSEE agrees that there may be some potential benefits from the use of instrumentation on the riser, additional research and study needs to be done before BSEE could determine whether such a substantive requirement should be added to the regulations. If future research or study reports or other information becomes available to BSEE warranting this additional requirement, BSEE may propose revision of this section in a future rulemaking.

Comments Related to Proposed § 250.416(b)(1)—Diverter Systems

Summary of comments: Another commenter was concerned that proposed § 250.416(b)(1) would require information in the APD about annular BOPs in diverter housings, even though not all diverters use annular elements. The commenter stated that some diverters use ''insert elements,'' which are not the same as annular BOPs, and recommended that BSEE replace ''annular BOP'' in proposed § 250.416(b)(1) with ''sealing element.''

• *Response:* BSEE agrees with the commenter that not all diverters use annular BOPs. Accordingly, BSEE has revised this section in the final rule by replacing ''annular BOP'' with ''element,'' which covers all of the different types of components (including annular BOPs and sealing elements) that may be installed in the diverter housing.

What must I provide if i plan to use a mobile offshore drilling unit (MODU)? (§ 250.417)

BSEE proposed to remove and reserve this section and to move the content of this former section to proposed § 250.713. BSEE received no comments on the proposed removal and reservation of this section and the final rule takes that action.

What additional information must I submit with my APD? (§ 250.418)

This section of the existing regulation specified certain additional information (*e.g.,* rated capacity of the drilling rig, drilling fluids program) that must be included in an APD. BSEE did not propose any changes to paragraphs (a) through (f) of the existing regulation, which are therefore retained unchanged. BSEE proposed to revise paragraph (g) of the existing regulation, which requires operators to seek approval for plans to wash out or displace cement to facilitate casing removal upon well abandonment, by adding a requirement to describe how far below the mudline the operator plans to displace cement and how the operator will visually monitor returns. This proposed change would provide information to assist BSEE in deciding whether to approve such plans. BSEE received no substantive comments on this proposed addition to paragraph (g), which is included in the final rule as proposed.

What well casing and cementing requirements must I meet? (§ 250.420)

This section of the existing regulation imposes specific requirements for casing and cementing of all wells. BSEE proposed to revise the introductory text of this section, to re-designate former paragraph (a)(6) as paragraph (a)(7), and to insert a new paragraph (a)(6) that requires adequate centralization to help ensure proper cementation. BSEE also proposed to add a new paragraph (b)(4), requiring approval by the District Manager of changes to certain planned casing parameters, as well as a new paragraph (c)(2), requiring the use of a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time and thus enhance wellbore stability during cementing. BSEE received and considered comments on proposed paragraphs (a) and (c) and, as explained in the following responses, has included proposed paragraph (a) in the final rule without change. BSEE also included proposed paragraph (c) in the final rule, but revised proposed paragraph (c)(2) slightly in response to this section's summary of comments and responses.

Comments Related to Proposed § 250.420(a)—Centralizers

Summary of comments: One comment was submitted by multiple commenters on the proposed requirement in § 250.420(a)(6) for use of centralization to ensure proper cementation. It stated that the proposed requirement needs to be changed to allow for methods other than centralizers to meet the cementing requirements of this section because there are instances where using centralizers will actually increase risk. The commenters provided examples of the need for centralization, including the inability to ream down casing and the likelihood of greater casing wear if the pipe is not centered. The commenters also provided examples, however, of why centralizers should not be the exclusive method for centralization, including the assertion that centralizers may increase the chance of pack-off, increase the number of connections in the casing string (because centralizer subs are often the only option for centralization), and damage the wellhead components (due to centralizer pass through). One commenter recommended the following alternative language: ''Provide adequate centralization and/or other methods to aid proper cementation to meet well design objectives within the constraints imposed by hydraulic, operational, logistical or well architecture limitations (ref. [API] Standard 65–2 2nd Edition.)''

• *Response:* The commenter incorrectly assumes that § 250.420(a)(6) provides for the use of centralizers only. That provision does not specify or limit how centralization should be achieved. There are many options to ensure centralization besides the use of centralizers, and BSEE expects that multiple methods may be required to ensure adequate centralization. BSEE relies on industry best practices and industry standards to help determine suitable methods for centralization while cementing. BSEE also disagrees with the commenter's recommended inclusion of a reference to API Standard 65–2 (2nd Edition), since a written description of how the operator evaluated the relevant practices is already required under § 250.415(f) (''What must my casing and cementing programs include?''). Therefore, no changes to proposed paragraph (a)(6) are necessary, and BSEE has included that paragraph in the final rule as proposed.

Comments Related to Proposed § 250.420(c)—Cement Compressive Strength

Summary of comments: One commenter suggested that BSEE increase the required compressive strength of cement (500 psi) under proposed § 250.420(c)(1) in order to reduce the risk of cement failure, especially in zones of critical cement where pressures and stresses are higher. The commenter also recommended adding a requirement for the cement mixture in the zone of critical cement to meet a 1,200 psi compressive standard within 72 hours.

• *Response:* BSEE disagrees and has retained the proposed language requiring 500 psi compressive cement strength, which is the same as the requirement in the former paragraph (c), in the final rule. This requirement is also consistent with the provisions in API RP 65 part 2, already incorporated in the existing regulations, and with industry practice.

Comments Related to Proposed § 250.420(c)(2)—Cementing

Summary of comments: One comment was submitted by multiple commenters on the requirements in proposed § 250.420(c)(2) for use of weighted fluids during cementing. The comment stated that the proposed casing and cementing requirements increase the risk of lost circulation, which will result in failure to achieve zonal isolation. The commenter suggested that, if § 250.420(c)(2) refers to conditions at the center of the well, the language should be revised to provide: ''You must use a weighted fluid during displacement.''

• *Response:* BSEE agrees with the commenter and has revised § 250.420(c)(2) in the final rule by clarifying that a weighted fluid must be used ''during displacement.'' This revision will help resolve the commenter's concerns about the weighted fluid being in the center of the well.

What are the casing and cementing requirements by type of casing string? (§ 250.421)

This section of the existing regulation specifies casing and cementing requirements applicable to certain types of casing strings (*e.g.,* drive or structural strings, conductor strings). BSEE did not propose any changes to paragraphs (a) and (c) through (e) of the existing regulation, which are therefore retained unchanged. BSEE proposed revising former paragraph (b), however, to specify that if oil, gas, or unexpected formation pressure is encountered, the operator must set conductor casing immediately, above the encountered zone, even if that is before the planned casing point. This proposed provision was intended to ensure that conductor casing is not placed across a hydrocarbon zone. BSEE also proposed to revise former paragraph (f) to eliminate the potential use of liners as conductor casing. This proposed revision would help ensure that the drive pipe is not exposed to wellbore pressures. BSEE received and considered comments on proposed paragraphs (b) and (f) and, as explained in the following responses, has retained proposed paragraph (b) in the final rule without change. However, the final rule revises the proposed language in paragraph (f) as discussed in the following responses and in part V.C of this document.

Comments Related to Proposed § 250.421(b)—Conductors

Summary of comments: Some comments on proposed § 250.421(b) requested clarification as to whether the 22-inch and 20-inch casing used in deepwater operations is considered surface pipe and therefore subject to regulation under § 250.421(c) (requirements for surface casing) rather than § 250.421(b) (requirements for conductor casing). If BSEE agrees with that view, the commenter has no objection to proposed § 250.421(b) with regard to 20- and 22-inch casing.

A commenter also requested confirmation that drive pipe and jetted pipe are considered structural pipe and therefore are subject to regulation under former § 250.421(a) (requirements for drive or structural casing) rather than the proposed § 250.421(b). If BSEE agrees with that view, the commenter has no objection to proposed § 250.421(b) with regard to drive pipe and jetted pipe.

One commenter suggested rewording the proposed revision to the existing requirement for setting casing immediately upon encountering oil, gas, or unexpected formation pressure before the planned casing point. The language of the proposed rule would require the casing to be set above the encountered zone. While the commenter did not object to the proposed revision, it suggested deleting the phrase ''before the planned casing point'' from the former and proposed regulatory text, and adding to the end of that provision the phrase ''even if it is before the planned casing point.''

Another commenter suggested a change to a longstanding cementing requirement in existing (and proposed) § 250.421(b) for verification of annular fill by observation of cement returns or, when observation is not possible, by using additional cement to ensure fill-back to the mudline. The commenter indicated that, due to the long distances between the platform and the mud line at deepwater locations, excess hydrostatic cement pressure does not allow for a full column of cement to reach the platform level, making visual observation problematic. The commenter suggested that BSEE address this concern by allowing use of lift pressure calculations or ''tag and circulate'' to confirm visual evidence of cement location, and by adding language to the cementing provisions in § 250.421(b) that would require operators to discuss the cement fill level with the District Manager when ''drilling in deeper water on fixed structures, where it may not be feasible to observe cement return.''

• *Response:* BSEE agrees that 20- and 22-inch casing may be considered surface pipe and, thus, subject to § 250.421(c). BSEE also agrees that drive pipe and jetted pipe can be considered structural pipe and, thus, subject to § 250.421(a). Accordingly, no change to the proposed language in paragraph (b) is necessary on those points.

BSEE does not agree that the proposed conductor casing requirement for encounters with oil, gas or unexpected formation pressure that occur before the planned casing point should be reworded as suggested by the commenter. The casing requirements under former and proposed § 250.421(b) state that if oil, gas or unexpected formation pressure is encountered before the planned casing point, casing must be set immediately; the only change proposed by BSEE to paragraph (b) was to clarify that, in such a case, the casing must be set above the encountered zone. BSEE does not believe that the commenter's suggested rephrasing would add any extra clarity or change the meaning of the proposed language in any useful way.

Finally, BSEE did not propose any changes to the existing cementing requirements for conductors. As described previously, the proposed change to § 250.421(b) clarifies the location where conductor casing must be set if the operator encounters oil or gas or unexpected formation pressure before the planned casing point; *i.e.,* above the encountered zone. In any case, BSEE does not agree with the suggested revision to the cementing requirements with regard to deepwater drilling. Current cementing requirements, as reflected in former and proposed § 250.421(b), already provide that if visual observation of cement returns from the annular is not possible, additional cement must be added to ensure cement returns to the mudline. To date, BSEE is unaware of any actual problems from applying that practice reflected in the regulation to fixed platforms drilling in deeper water; thus, there is no need to add the language suggested by the commenter. If any actual problems with that approach arise in the future, the operator should consult the District Manager regarding appropriate action and, if warranted, request approval of alternative procedures or equipment under § 250.141.

Comments Related to Proposed § 250.421(f)—Casing and Liners

Summary of comments: With regard to proposed § 250.421(f)—revising existing casing requirements for liners by prohibiting use of liners as conductor casings—commenters raised concerns about how casing would be treated in deepwater riserless operations. One commenter suggested that the cementing requirements should apply to surface wellhead systems where structural casing extends back to the surface facility, and stated that conductor liner is an effective option for use as casing in mud line suspension completion systems. The commenter suggested that BSEE add the following text to § 250.421(f):

> A casing string whose top is above the mudline and that has been cemented back to the mudline will be not considered a liner. When conductor liner systems are needed in special applications, such as mud line suspension systems or drilling only applications, you must receive approval from the District Manager. You may not use a liner as conductor casing when surface wellhead systems are in use without mud line suspension systems and the structural casing extends back to the surface facility.

In support of the suggested change, the commenter stated that, for deepwater operations, this language would allow large outside diameter conductor hung in the supplemental wellhead adapter to be used as intended (*i.e.,* as a conductor) without being considered a liner subject to the liner cementing requirements.

• *Response:* BSEE agrees with the commenter that when the casing string top is above the mudline and has been cemented back to the mudline, the casing string should not be considered a liner. Accordingly, to clarify this intent, BSEE has revised the casing requirements in final § 250.421(f) to state that ''[a] subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.'' BSEE also agrees with the commenter that a large outside diameter conductor hung in the supplemental wellhead adapter should not be considered a liner. No change to the language of paragraph (f) is necessary on this point.

Comments Related to Proposed §§ 250.421(b) and (f)—Centralizing Casing

Summary of comments: One commenter supported the proposed new requirements in §§ 250.421(b) and (f), but suggested that BSEE add more specific instruction on how to centralize casing (*e.g.,* by specifying centralization requirements according to casing type). The commenter stated that if casing inside the well is not properly centralized, it will have thinner cement, or possibly no cement, where the pipe is near or in contact with the earthen wall. The commenter noted that thin areas of cement are easily cracked and damaged. The commenter noted further that cement that is not well-bonded to the outside of the casing or earthen hole, or that is damaged by subsequent well activities, creates a conduit for hydrocarbon movement, which increases the risk of losing well control. The commenter suggested that, at a minimum, surface casing should be centralized at the shoe and at every fourth casing joint and that intermediate and surface casing should be centralized at the base and top and at every tenth casing joint.

The commenter also suggested that additional centralizers should be used in highly deviated well sections. This commenter also recommended that BSEE change the proposed regulation to require that: (a) The surface casing be set deep enough to provide a competent structure to support the BOP and to contain any formation pressures that may be encountered before the next casing is run; (b) the entire surface casing annulus should be cemented to the surface (presumably the mudline); and (c) the surface casing must stop above any significant pressure zone or hydrocarbon zone to ensure the BOP can be installed prior to drilling into a pressure zone or into hydrocarbons.

• *Response:* BSEE agrees with the comment that requiring centralization will increase the probability of a successful and effective cement job. However, BSEE does not agree that centralization requirements should be included in § 250.421, as suggested by the commenter. BSEE proposed, and § 250.420(a)(6) of the final rule requires, adequate centralization (which does not mean the use of centralizers only) to ensure proper cementing programs. In addition, final § 250.420(a)(7)—formerly § 250.420(a)(6)—already requires that operators submit certifications signed by registered PEs that the casing and cementing design is appropriate and sufficient. These provisions will help ensure that casing is properly centralized. In addition, existing § 250.415(f) requires that the cementing and casing programs included in the APD describe how the operator uses API Standard 65—part 2 to evaluate best practices, including best practices for centralizing casing. This also helps ensure that casing is properly centralized. Accordingly, BSEE did not propose any changes to the surface casing provisions under former § 250.421 with respect to centralization, and no change to the former or proposed requirements are necessary on this point.

Comments Related to Proposed § 250.421(f)—Liner Lap Length

Summary of comments: A commenter did not agree with the requirement in proposed § 250.421(f) to have a liner lap length specified for liners with liner top packers. The commenter stated that liner lap length requirements in production wells may adversely affect the ability to complete the well efficiently.

• *Response:* BSEE agrees with the commenter's intent and has revised the proposed cementing requirements for liners by adding language to final § 250.421(f) stating that as provided by (d) and (e), if you have a liner lap and are unable to cement 500 feet above the previous shoe, you must submit and receive approval from the District Manager on a case-by-case basis. This revision provides additional flexibility to ensure that production wells are completed efficiently.

What are the requirements for casing and liner installation? (§ 250.423)

This section of the existing regulation was entitled ''What are the requirements for pressure testing casing?'' BSEE proposed to change the former title of this section to more accurately reflect proposed changes within the section that establish requirements for installing casings and liners. BSEE also proposed to revise paragraphs (a) through (c) of former § 250.423 to clarify that liner latching mechanisms, if applicable, need to be engaged upon successfully installing and cementing the casing string or liner. These proposed revisions were intended to reinforce the importance of properly securing liners in place to ensure wellbore integrity. BSEE received and considered comments on the proposed revisions and the language in proposed paragraphs (a) and (b) has been revised as discussed in the following responses. Proposed paragraph (c), however, is included in the final rule without change.

Comments Related to Proposed § 250.423(a) and (b)—Ensuring Lockdown Mechanism Is Engaged

Summary of comments: One commenter recommended that the introductory sentence in proposed § 250.423—regarding casing and liner installation—be changed in order to provide greater clarity for industry.

Multiple commenters raised the concern that the language in proposed § 250.423(a) and (b) does not define or explain how to measure success in ensuring that latching/locking mechanisms are engaged after ''successfully installing and cementing'' the casing string and liner, respectively. They stated that many systems do not have a way to ''ensure'' that the lockdown mechanism is properly engaged; all they can do is ensure that the proper procedures to set the lockdown mechanism are followed. The commenters recommended that BSEE remove the word ''successfully'' from §§ 250.423(a) and (b) and say instead that, ''[y]ou must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string.''

• *Response:* BSEE does not agree that the suggested change to the introductory sentence in proposed § 250.423 is necessary to avoid confusion. The commenter did not explain why that sentence is unclear or why the commenter's suggested change would make the language clearer. In fact, the introductory sentence in the proposed rule was exactly the same as the language in existing § 250.423(b), and BSEE is unaware of any confusion regarding the meaning of that language. Accordingly, BSEE has not changed that sentence in the final rule.

BSEE agrees with the suggestion that more guidance is needed in this section for operators to determine when casing strings and liners have been successfully installed and cemented. Therefore, we have revised proposed § 250.423(a) and (b) in this final rule to include references to the cementing requirements of § 250.428(c). In effect, the latching mechanisms or lock down mechanisms must be engaged upon successfully installing and cementing the liner. If the operator determines under § 250.428(c) that the cement job is adequate (*i.e.,* successful), then the latching/locking mechanisms should be engaged. If there are indications of an inadequate cement job, actions should be taken in accordance with § 250.428 to ensure proper cementation before the latching or locking mechanisms are engaged.

Comments Related to Proposed § 250.423(c)—Proper Casing or Liner Installation

Summary of comments: One commenter suggested that BSEE add a new requirement to § 250.423(c) for monitoring and verification of make-up and torqueing of casing and tubular connections. The commenter suggested the use of torque/turn evaluation equipment when installing production casing and tubing to confirm that thread mating has been performed according to applicable specifications.

• *Response:* BSEE does not agree that these suggested changes are necessary to ensure proper installation of casing and tubing. BSEE already requires a pressure test on the casing seal assembly under former § 250.423(b)(3)—now § 250.423(c)—and submittal to BSEE of both the test procedures and test results, in order to verify the integrity of the casing and connections. Therefore, no additional language is needed to help confirm casing integrity.

What are the requirements for prolonged drilling operations? (§ 250.424)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.722. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the requirements for pressure testing liners? (§ 250.425)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.721. BSEE received no comments on the proposed removal and reservation of this section and the final rule takes that action.

What are the recordkeeping requirements for casing and liner pressure tests? (§ 250.426)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.746. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the requirements for pressure integrity tests? (§ 250.427)

This section of the existing regulation requires pressure integrity testing below the surface casing or liner and at certain drilling intervals. BSEE proposed to revise former paragraph (b) of this section to clarify that operators must maintain the safe drilling margins required by proposed § 250.414. Although BSEE received and considered comments on this proposed requirement, the final rule includes this paragraph as proposed for the reasons discussed in the following responses.

Comments Related to Proposed § 250.427(b)—Safe Drilling Margin

Summary of comments: Multiple commenters raised the concern that changing the casing design for wells in order to maintain the safe drilling margins specified in proposed § 250.414 could make some wells uneconomical, due to the need for smaller completions and thus, potentially uneconomical production rates.

Although BSEE only proposed a minor change to existing § 250.427 (*i.e.,* adding a cross-reference in paragraph (b) to the new safe drilling margin provisions in proposed § 250.414), these same commenters also raised concerns with the existing requirement in § 250.427(b) that safe drilling margins must be maintained and that drilling must be suspended and the situation remedied when the drilling margins cannot be maintained. The commenters stated that suspending drilling to set pipe based on the proposed 0.5 ppg safe drilling margin—which they considered a legacy drilling margin from shallow shelf wells—would have severe negative consequences for many deepwater or depleted zone wells being drilled today and to be drilled in the future. In addition, the commenters claimed that maintaining the proposed 0.5 ppg safe drilling margin may require so many additional casing strings that it could hinder many deeper well designs in that they would no longer have the capability to run additional casing strings as needed to meet the applicable containment requirements. All commenters on this issue recommended that BSEE revise the second sentence in § 250.427(b) to state that ''[w]hen you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation in accordance with accepted industry practices as documented in API Bulletin 92L or as otherwise approved by the District Manager.'' Two of the commenters also suggested that BSEE require the operator to assess risk in addition to receiving District Manager approval for the remedial activity.

• *Response:* As discussed elsewhere in this document (see part V.B.1), based on other comments BSEE has revised the safe drilling margin requirements in final § 250.414 to provide operators more flexibility in determining a proper safe drilling margin. The revisions to that section resolve most, if not all, of the concerns raised by the commenters in connection with proposed § 250.427. In this final rule, BSEE is not specifying how the operator must remedy the situation when the safe drilling margin cannot be maintained. Accordingly, BSEE has not made the changes to proposed § 250.427 requested by the commenters. However, BSEE will evaluate API Bulletin 92L and, if BSEE determines that it is appropriate to require application of that standard to remedial actions when safe drilling margins cannot be maintained, BSEE may propose incorporating that standard in the regulations in a separate rulemaking.

What must I do in certain cementing and casing situations? (§ 250.428)

This section of the existing regulation describes actions that must be taken when certain situations (*e.g.,* unexpected formation pressures) are encountered during casing or cementing operations. BSEE did not propose changes to paragraph (a) or paragraphs (e) though (i). BSEE proposed to revise paragraph (b) of this section to require District Manager approval for proposed hole interval drilling depth changes (greater than 100 feet total vertical depth), and submittal of a certification that a PE has reviewed and approved the proposed changes. These proposed requirements were intended to assist BSEE in verifying the actual well conditions.

BSEE also proposed to revise former paragraph (c), to clarify the requirements for actions that must be taken if there is an indication of an inadequate cement job, and former paragraph (d), clarifies that if the cement job is inadequate, the District Manager must approve all proposed remedial actions (except immediate action to ensure safety or to prevent a well-control event). In addition, BSEE proposed to add paragraph (k) (concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner), to require certain actions to assist BSEE in assessing the structural integrity of the well. After consideration of comments on these proposed revisions, BSEE has included proposed paragraphs (b), (c), and (d) in the final rule without change. However, as discussed in the following responses, BSEE has revised the language of proposed paragraph (k) in the final rule.

Comments Related to Proposed § 250.428(b)—Changing Casing Setting Depths or Hole Interval Drilling Depth

Summary of comments: One commenter raised concerns that the proposed changes to existing § 250.428(b), which specifies what operators must do when they need to change casing setting depths or hole interval drilling depths, would be too restrictive. The commenter asserted that if the requirement was limited to changes that exceed 300 feet TVD—instead of 100 feet TVD as proposed—it would minimize unnecessary resubmittals of proposed changes to District Managers for approval and certifications of the proposed changes by PEs.

• *Response:* BSEE does not agree with this comment. Changing the requirement in § 250.428(b) from 100 feet TVD to 300 feet TVD would adversely affect the source control and containment capabilities required by § 250.462(a) since it could affect the performance and integrity of the well as designed and affect the determination of whether a full shut-in can be achieved. Accordingly, BSEE made no changes in the final rule to the proposed language of paragraph (b) in response to this comment.

Comments Related to Proposed § 250.428(b) and (d)—PE Certification

Summary of comments: Multiple commenters raised concerns with the requirement in proposed § 250.428(b) and (d) that a PE certify that he or she has reviewed and approved proposed changes to casing setting depths as well as proposed changes to the well program to remedy an inadequate cement job. The commenters asserted that PE certification of proposed changes to casing setting depths should be required only if those changes would affect the effectiveness of a barrier or if the change in the casing setting depth would lead to a significant change in the cementing program (*e.g.,* exposure of an additional hydrocarbon zone).

In case of an inadequate cement job, the commenters recommended that BSEE require that: (1) The operator submit a remedial action plan that includes immediate action and planned future action; (2) the District Manager approve the remedial action, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event; (3) if the operator completes any unapproved immediate action to ensure the safety of the crew or to prevent a well-control event, the operator must submit a description of the action to the District Manager when that action is complete; and (4) any changes to the well program (implicitly including casing or cement programs) that can impact the effectiveness of the barrier will require a certification by a PE that he or she reviewed and approved the proposed changes, and the changed well programs must meet any other requirements of the District Manager.

One commenter also requested that BSEE clarify whether the PE certifications required by § 250.428 refer only to changes to the casing design and primary cementing plans and not to proposed changes included in an APM. The commenter suggested revising the PE certification language in that paragraph to read: ''certifying that the PE reviewed and approved the revised casing and/or cement program.''

• *Response:* BSEE does not agree that any of the changes to proposed § 250.428 suggested in these comments are necessary. BSEE does not agree that PE certifications for changes to casing setting depths should only be required when such changes would degrade barrier effectiveness. Changes to the casing setting depths could also affect the performance and integrity of the well as designed and determinations as to whether a full shut-in can be achieved. In addition, PE certification provides additional QA/QC and helps ensure that the actions are appropriate for the specific well. If an operator has any questions about what specific changes the PE must certify, the operator may contact the appropriate District Manager.

BSEE agrees, however, with the commenter's request that we clarify that the PE certification requirements in proposed § 250.428(b) and (d) apply only to the changes described in those paragraphs and not to other changes included in an APM. That is the correct interpretation of those provisions and no change to the proposed language of those paragraphs is necessary in the final rule.

Comments Related to Proposed § 250.428(c)—Indications of Inadequate Cement Job

Summary of comments: Several commenters recommended adding ''lift pressure analysis'' to the list of actions (*i.e.,* temperature survey, cement evaluation log, or combination of both) as an alternative method to determine the adequacy of the cement job under proposed § 250.428(c)(1). The commenters stated that cement lift pressure analyses are an industry-recognized alternative to cement evaluation logs for determining the top of cement.

Another commenter stated that the requirements in § 250.428(c) should be revised so that when a casing shoe is not set in hydrocarbons, only a shoe test would be required to confirm that the cement job was successful. On the other hand, the commenter suggested that if hydrocarbons are present, a shoe test would not be enough to confirm cement job success, and a combination of other techniques (including lift pressure analysis, radioactive tracers, and/or cement bond logging) should be required to confirm job success.

One commenter supported the proposed changes to § 250.428, but recommended that the diagnostic tests should also be run for all offshore wells to verify adequate cement placement. The commenter also recommended that the proposed requirements in § 250.428(d) for remedying inadequate cement jobs be strengthened to require a repeat cement evaluation log to verify that the cement repair was successful.

• *Response:* BSEE does not agree that the changes suggested by these comments are necessary. Lift pressure analysis and a shoe test by themselves are not conclusive indicators of an adequate cement job, and the additional techniques (*i.e.,* temperature survey or cement evaluation log or a combination of both) in § 250.428(c) may be necessary to assist in locating the top of the cement.

With regard to the comment on strengthening the requirements for remedial actions in proposed § 250.428(d), there is no need to specify that a repeat cement evaluation is necessary if there is any indication that the repair was inadequate. In such a case, § 250.428(c) would still apply, and the actions required by that paragraph, including a PE certification, must still be taken.

BSEE also does not agree with the suggestion that § 250.428(c) should apply to all wells, even if there is no indication of an inadequate cement job. When there is no indication of an inadequate cement job, the existing requirement to pressure test all casings and liners (formerly § 250.423, redesignated as § 250.721 in this final rule) provides a reasonable indication of a good cement job.

Comments Related to Proposed § 250.428(d)—Immediate Action Reporting

Summary of comments: Regarding the ''immediate action'' reporting requirement in § 250.428(d), one commenter asked whether there is an obligation for contractors to provide individual reports or to verify that such reports have been submitted by the operator. Regarding the remedial action reporting, another commenter asked whether BSEE had any expectation that a drilling contractor would submit this report.

• *Response:* As a general matter, BSEE looks to the designated operator to make filings on behalf of all lessees and owners of operating rights. This issue is discussed in more detail in part VI.B.5 of this document.

Comments Related to Proposed § 250.428(k)—Valves Used on the Drive Pipe

Summary of comments: With regard to proposed § 250.428(k)—specifying what an operator must do when it plans to use a valve on the drive pipe during cementing for conductor or surface casings or for liners—one commenter suggested that the reference to use of a valve was too limiting. The commenter suggested changing the word ''valve'' to ''barrier.'' This would make the requirements in § 250.428(k) applicable to pressure caps, stabs, or other barriers in addition to valves.

The commenter also pointed out that for subsea wells, several valves are normally used, one for each port; therefore, the proposed rule should not use the singular word ''valve.'' The commenter also said that it is common practice to use a secondary barrier (such as a pressure cap) to supplement a valve (*i.e.,* in case the valve leaks). Therefore, the commenter recommended that BSEE revise the proposed requirement that ''[y]our description [of the plan to use a valve] must include a schematic of the valve and height above the water line . . .'' to read: ''Your description must include a schematic of the primary and secondary barriers and height above mud-line. . . .''

• *Response:* BSEE agrees that changing ''valve'' to ''valves'' in § 250.428(k) is appropriate, and has revised the final rule accordingly. However, BSEE does not agree that the other changes suggested by the commenters are necessary. In proposed, and now final, § 250.428(k), the reference to valves is limited to valves used to verify visible cement returns, and thus it is expected that some cement will escape those valves. They do not serve the same purpose as other barriers.

What are the general requirements for BOP systems and system components? (§ 250.440)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.730. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the requirements for a surface BOP stack? (§ 250.441)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.733 and 250.735. BSEE received no comments on the proposed removal and reservation of this section and the final rule takes that action.

What are the requirements for a subsea BOP system? (§ 250.442)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.734. BSEE received no comments on the proposed removal and reservation, and the final rule takes that action.

What associated systems and related equipment must all BOP systems include? (§ 250.443)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.733, 250.734, and 250.735. BSEE received no comments on the proposed removal and reservation, and the final rule takes that action.

What are the choke manifold requirements? (§ 250.444)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.736. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the requirements for kelly valves, inside BOPs, and drill-string safety valves? (§ 250.445)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.736. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the BOP maintenance and inspection requirements? (§ 250.446)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.739. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

When must I pressure test the BOP system? (§ 250.447)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.737. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the BOP pressure tests requirements? (§ 250.448)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.737. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What additional BOP testing requirements must I meet? (§ 250.449)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.737. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are the recordkeeping requirements for BOP tests? (§ 250.450)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.746. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What must I do in certain situations involving BOP equipment or systems? (§ 250.451)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.738. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What safe practices must the drilling fluid program follow? (§ 250.456)

This section of the existing regulation specifies safe practices (*e.g.,* proper conditioning of drilling fluid) that must be included in a drilling fluid program. BSEE proposed no significant changes to paragraphs (a) through (i) of the existing regulation. However, BSEE proposed removing paragraph (j) of the existing regulation, re-designating former paragraph (k) as paragraph (j), and moving the content of former paragraph (j), which requires District Manager approval for displacing kill-weight fluid, to proposed § 250.720(b). This was intended to clarify that this requirement applies to all drilling, workover, completion, and abandonment operations. BSEE received no substantive comments on this provision of the proposed rule, and the final rule takes these actions.

What are the source control, containment, and collocated equipment requirements? (§ 250.462)

This section of the existing regulation was entitled ''What are the requirements for well-control drills?'' BSEE proposed to re-title and completely revise this section, and to move the contents of former § 250.462 to proposed §§ 250.710 and 250.711. As proposed, § 250.462 would require the operator to demonstrate the ability to control or contain a blowout event at the sea floor. Proposed paragraph (a) would require the operator to determine its source control and containment capabilities; proposed paragraph (b) would require that operators have access to, and the ability to deploy, source control and containment equipment (SCCE) necessary to regain control of the well; proposed paragraph (c) would require submittal of a description of the source control and containment capabilities before BSEE approves an APD; proposed paragraph (d) requires reevaluation by BSEE approval if certain events occur; and proposed paragraph (e) outlines maintenance, inspection, and testing requirements for specified containment equipment. After consideration of comments on the proposed section, and as explained in the following responses, BSEE has included paragraphs (a) through (d) in the final rule as proposed. BSEE has, however, revised the language of proposed paragraph (e) in the final rule.

Comments Related to Proposed § 250.462—Introductory Paragraph

Summary of comments: One commenter recommended that an ''alternate contingency plan'' be added at the end of the introductory paragraph to § 250.462 and also to the description of SCCE in § 250.462(c)(1) and (c)(3). The commenter asserted that this would provide an equivalent seabed source control and containment alternative, and that the proposed rule does not promote the development of alternative technologies that may be more effective than traditional responses.

- *Response:* BSEE does not agree with this comment. Companies are free to design any type of equipment as long as they demonstrate it has the capability to respond to a loss of well-control situation. Therefore, no changes are needed to this proposed section in response to this comment.

Comments Related to Proposed § 250.462(a)—Determining Source Control and Containment Capabilities

Summary of comments: Several commenters suggested revising proposed § 250.462(a)(2) to differentiate well designs that can be fully shut-in from those that can only be partially shut-in, and to require operators to ''verify,'' rather than to ''determine,'' that a full shut-in can be achieved. Some of these same commenters also recommended adding a new paragraph (a)(3) to require that an operator have the capability to: ''flow and capture the residual fluids to a subsea well.'' Commenters also suggested that the analyses required in proposed § 250.462(a)(1) and (2) be bolstered by stating that the analyses should be performed using the most current version of the well containment screening tool. Commenters stated that the BSEE-endorsed well containment screening tool provides the necessary analysis; operators have used this tool for over four years and submit it with all affected APDs. Commenters suggest that this currently accepted practice should be acknowledged and codified.

- *Response:* BSEE disagrees with the suggestion that the rule should require use of the well containment screening tool. Although the rule does not require operators to use that tool, it is an acceptable tool to use for the analyses required in final § 250.462(a)(1) and (2), and is typically included as a condition in APDs. Similarly, the other recommended changes to paragraph (a) are not necessary, since use of the well containment screening tool would lead to essentially the same results that the commenters' recommendations are intended to achieve.

Comments Related to Proposed § 250.462(b)—SCCE

Summary of comments: One commenter requested BSEE add subsea device connections or transition connections from one component to another to the equipment listed in § 250.462(b) as SCCE. The commenter asserted that for industry to progressively address safety, efficiency, timeliness, certainty in methods and systems to contain and capture reservoir fluid, BOP connections and containment points should be considered as SCCE.

- *Response:* BSEE does not agree with the requested addition to proposed paragraph (b). The equipment requirement that the commenter recommends adding to this provision is already addressed in the APD and the well containment screening tool. BSEE will not approve an APD unless the operator ensures that it has the equipment needed. BSEE does not specify what equipment is to be used for a given scenario under final § 250.462(b); that provision requires only that the equipment be accessible and capable of responding to an oil spill.

Summary of comments: Some commenters requested other changes to proposed § 250.462(b), asserting that SCCE requirements should be specific to each well and that cap and flow equipment should not be required for wells that are specifically designed for shut-in on a full hydrocarbon column. Among other things, the commenters requested that BSEE clarify that SCCE means the capping stack, cap and flow system, and ''(where applicable . . . , containment dome (*i.e.,* localized, non-pressurized, subsea fluids collection device),'' and that cap and flow systems (including containment domes) are not required for wells that are designed for shut-in on a full column of hydrocarbons.

- *Response:* BSEE does not agree that the requested changes are necessary. The initial screening of a well might indicate that it can be fully shut-in, but the operator should always have the equipment necessary and available if something happens that would change the outcome of the situation from a full shut-in to a cap and flow scenario. The initial screening presents a model outcome based on what is known at the time that the APD is submitted. BSEE realizes there is always the potential that, although the results of the initial screening indicate that the well could be controlled through a full shut-in (capping only), the well could actually require cap and flow if an actual loss of well control were to occur. BSEE wants to ensure that the operator is prepared for this situation and has all of the assets that may be needed available to respond to a loss of well control.

Comments Related to Proposed § 250.462(c)—Description of Source Control and Containment Capabilities

Summary of comments: Regarding proposed § 250.462(c), commenters raised questions and recommended wording changes. Three commenters stated that industry already submits the required documents with each permit application (RP checklist) and suggested that the Regional Containment Demonstration (RCD), once approved, would satisfy the new requirements. Other commenters suggested retaining flexibility for containment capabilities (*i.e.,* pre-installed capping device for spar and TLPs, in-situ burning and dispersants) and suggested that BSEE revise § 250.462(c)(1) to allow an ''approved alternate contingency plan'' as an alternative to a description of containment capabilities for controlling and containing a blowout event at the seafloor. Commenters also suggested that BSEE change proposed § 250.462(c)(3) to allow ''other approved contingency plan equipment'' as an alternative to information showing that the operator has access to and ability to deploy all equipment required by paragraph (b).

- *Response:* BSEE agrees that the RCD may indicate source control and containment capabilities, but operators should not assume that pre-installed containment equipment (*i.e.,* pre-installed capping device) will work. This equipment is located on the rig and does not replace a capping stack, which is located elsewhere and can be used in the event that the equipment located on the rig fails. Therefore, BSEE requires operators to demonstrate that they are ready to respond with additional equipment (*i.e.,* capping stack), if necessary. Moreover, subsea dispersant equipment are not considered source control or containment devices, but rather equipment that is collocated and deployed alongside SCCE operations. Accordingly, BSEE does not agree with the recommended changes to proposed § 250.462(c).

Comments Related to Proposed § 250.462(d)—Notification of BSEE

Summary of comments: Some commenters requested a change to the requirements in proposed paragraph (d) to advise BSEE of any well design change and to suspend operations until the required out-of-service SCCE is repaired or replaced. The commenters asserted that the proposed requirement to advise BSEE of any well design change will pose an undue burden on both the operator and BSEE. They also claimed that it is important to clarify that only well design changes which negatively impact the results of the well containment screening tool require notification to BSEE. They also suggested that a risk-based approach should be adopted, that risk should be managed to the lowest possible level, and that if BSEE's regional representatives are not satisfied that the risk justifies continuing operations, then operations should be halted and the permit withdrawn. Therefore, the commenters suggested that BSEE revise proposed § 250.462(d)(1) to set conditions on when BSEE should be advised of well design change; *i.e.,* that BSEE should be advised only in the event of ''any changes in the well design or well conditions that require a revised permit to drill to be submitted and can impact the results of the well containment screening tool.''

One commenter also recommended that, since proposed § 250.462(d)(2) would require the operator to contact the BSEE Regional Supervisor to reevaluate source control and containment capabilities if required SCCE is out of service, the operator should be required to secure the well and suspend drilling operations until the SCCE equipment is repaired or replaced and returned to full active service.

- *Response:* BSEE does not agree that any change to proposed paragraph (d) is warranted by these comments. BSEE will require notification if there are any well design changes. However, BSEE is not specifying the approach to be used for reevaluation of source control and containment capabilities; the well containment screening tool mentioned by the commenter would be acceptable in most circumstances. The notifications for the well design changes must be submitted at the time the operator submits a revised permit. BSEE will evaluate, on a case-by-case basis, whether there is adequate equipment available if the SCCE is out of service, and will then determine if the operator needs to suspend drilling operations.

Comments Related to Proposed § 250.462(e)—Maintaining, Testing, and Inspecting SCCE

Summary of comments: BSEE received several comments on the cap and flow requirements in proposed § 250.462(e). In general, the comments stated that it is not necessary to have ''cap and flow'' capacity if a capping stack is capable of achieving a complete shut-in of the well. The commenters also stated that if an operator's evaluation, using the BSEE-endorsed well containment screening tool, indicates that a wellbore can be completely shut-in while maintaining full integrity, then cap-and-flow well design and equipment should not be required for the permit. The commenters suggested, however, that the cap-and-flow well design and equipment should be required for permit approval if the well containment screening tool indicates loss of wellbore integrity when attempting a complete shut-in. Another comment concerning the maintenance, testing, and inspection of SCCE, as required in proposed § 250.462(e), suggested that BSEE should use the API terminology of ''pressure containing,'' rather than the proposed ''pressure holding,'' to eliminate the possibility of misinterpretation. It was also suggested that BSEE consider referring to API RP 17W in paragraph (e) to provide more clarity regarding documentation, document retention, and reporting requirements in the proposed table of requirements.

- *Response:* Operators should always be ready to respond to a discharge or loss of well control requiring cap and flow response elements, even if the initial screening suggests that the wellbore can be fully shut-in. However, BSEE agrees that the terminology change suggested by the commenters (replacing ''pressure holding'' with ''pressure containing'') will improve consistency with current industry usage and provides a better description of the purpose of the equipment. Accordingly, BSEE included that revision in final § 250.462(e).

We do not agree, however, that API RP 17W should be incorporated in the final rule at this time. BSEE did not propose to incorporate that standard and, although we may consider this document for incorporation in the future, using the evaluation process previously described, if we decide it is appropriate to incorporate that standard, we will do so through a separate rulemaking.

Comments Related to Proposed § 250.462(e)—Testing SCCE

Summary of comments: Commenters provided specific comments on, and recommended revisions to, proposed § 250.462(e), suggesting that BSEE develop alternative testing methods and frequencies that will provide an equivalent or greater degree of verification. Some comments also addressed how pressure testing should be witnessed. Several commenters suggested that there should only be one witness during pressure testing to avoid duplication and the spending of unnecessary resources. Commenters suggested that the witness should be either BSEE or a BAVO, but not both.

One commenter stated that the required function testing of capping stacks should be conducted quarterly, and that pressure testing of all critical capping stack components should be conducted on a biennial basis.

Commenters also suggested changes to the proposed paragraph (e) to implement their comments, including changing ''pressure holding critical components'' to ''pressure containing critical components, and changing the proposed witnessing requirement to allow witnessing by BSEE ''and/or an independent third-party.''

- *Response:* As discussed in the previous response, BSEE has agreed to change ''pressure holding critical components'' to ''pressure containing critical components'' in the final rule. This change provides a better description of the purpose of the equipment. BSEE has also addressed the concerns the commenters expressed on the use of BAVOs elsewhere in this document, in regard to §§ 250.731 and 250.732 and other BAVO-related provisions. BSEE disagrees with the suggestion that the proposed requirement that both BSEE and a BAVO witness the pressure tests be revised to require the presence of only one or the other. It is important for BSEE and a BAVO to witness all pressure testing, whenever it is possible for BSEE to be present. Although BSEE may not be available to witness every test, BSEE expects that it will witness a pressure test and a function test at least once per year. Therefore, BSEE has determined that is necessary to require a BAVO to witness every pressure test so that BSEE can be assured that every test is performed correctly. BSEE has also slightly revised the language in final § 250.462(e)(1)(ii) to clarify that if a BSEE representative is not available, the test may be witnessed by a BAVO alone.

Comments Related to Proposed § 250.462(e)(2)(i)—Production Safety Systems Used for Flow and Capture Operations

Summary of comments: Several commenters suggested changes to the § 250.462(e)(2)(i) requirements for production safety systems used for flow and capture operations. The commenters stated that subpart H of part 250 (§§ 250.800 through 250.808) includes requirements for items below the wellhead (*i.e.,* subsurface valves) that do not encompass source control equipment. They recommended the following change in the proposed text of paragraph (e)(2)(i): ''Meet the requirements set forth in § 250.800 through 250.808, Subpart H, excluding equipment requirements that would be installed below the wellhead or that are not applicable to the cap-and-flow system.''

• *Response:* BSEE agrees with the commenter that this provision should not apply to downhole safety systems and has revised the final rule to exclude equipment below the wellhead.

Comments Related to Proposed § 250.462(e)(3)—Inspection of Subsea Utility Equipment

Summary of comments: Several commenters suggested BSEE should define the expectations for inspection of subsea utility equipment in § 250.462(e)(3). They asserted that subsea utility equipment—such as debris removal kits, hydraulic power units, coiled tubing, hydrate control, and dispersant injection equipment,—is in common use as provided by contractors and specific equipment is not designated in those retainer agreements. They suggested revising the language in proposed paragraph (e)(3) to more clearly define the scope of equipment that needs to be available for inspection, as follows: ''Subsea utility equipment, requirements, you must: Have all equipment utilized uniquely for containment operations available for inspection at all times.''

• *Response:* BSEE agrees that the nature of the equipment that the operator needs to make available to BSEE for inspection can be better defined. Accordingly, BSEE has decided to revise the requirement in final § 250.462(e)(3) to state, ''[h]ave all referenced containment equipment available for inspection at all times.'' BSEE also revised this section to include a parallel provision for collocated equipment. If the equipment is in use for other normal operations, BSEE expects that it would inspect similar equipment provided by the same contractor (*i.e.,* coiled tubing).

When must I submit an application for permit to modify (APM) or an end of operations report to BSEE? (§ 250.465)

This section of the existing regulation specifies circumstances that require an operator to submit an APM or EOR (Form BSEE–0125) and the timeframes for doing so. BSEE did not propose any changes to this section of the existing regulation, except former paragraph (b)(3). Accordingly, the remainder of former § 250.465 is retained in the final rules without change. BSEE proposed to revise former paragraph (b)(3) to clarify that, if there is a revision to the drilling plan, major drilling equipment change, or a plugback, the operator must submit an EOR within 30 days after completing the work. This proposed provision was intended to help ensure that BSEE has current well information. BSEE received no substantive comments on proposed paragraph (b)(3), and the final rule includes that paragraph as proposed.

Comments Related to Proposed § 250.465—Timeliness and Consistency of BSEE Action on Permit Applications

Summary of comments: Although the only revision to § 250.465 that BSEE proposed was to former § 250.465(b)(3), regarding submittal of EORs (*i.e.,* to incorporate the new EOR requirements in proposed § 250.744), one commenter raised general concerns regarding the timeliness and consistency of BSEE action on permit applications. The commenter stated that, although operators strive to submit permit applications well in advance of planned operations, BSEE engineers are not able to timely process new applications. Frequently BSEE is reviewing new permit requests just prior to a rig arriving, or after a rig is already on location, sometimes just before operations would have begun. The commenter also asserted that final approval of APDs and APMs is often received after operations begin, resulting in updated regulatory stipulations or changes to plans which can lead to non-compliance issues, confusion between parties, and could result in increased operational risks.

• *Response:* BSEE understands the concerns raised by these comments and is making efforts to improve the timeliness of its review and approval of APDs and APMs. With regard to this rulemaking, however, because these comments are outside the scope of the proposed rule, BSEE has not made any revisions concerning APM or APD submittals or approvals. Final paragraph (b)(3) requires submission of EORs within 30 days of completing work and does not address the submission of permit applications.

What records must I keep? (§ 250.466)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.740. BSEE received no substantive comments on this provision, and the final rule takes that action.

How long must I keep records? (§ 250.467)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.741. BSEE received no comments on the proposed removal and reservation, and the final rule takes that action.

What well records am I required to submit? (§ 250.468)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.742 and 250.743. BSEE received no comments on the proposed removal and reservation, and the final rule takes that action.

What other well records could I be required to submit? (§ 250.469)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.745. BSEE received no comments on the proposed removal and reservation, and the final rule takes that action.

Subpart E—Oil and Gas Well-Completion Operations

General Requirements (§ 250.500)

This section of the existing regulation requires that well-completion operations be conducted in a way that protects human and animal life, property, OCS natural resources, National security and the environment. BSEE proposed to revise this section by adding language requiring operators to follow the applicable requirements of proposed new Subpart G (in addition to Subpart E). BSEE also proposed to replace the word ''shall'' with ''must'' throughout this section in order to clarify that the provision is mandatory. BSEE received no substantive comments on these proposed revisions to the existing regulation and has made no changes to the proposed language in the final rule.

Equipment Movement (§ 250.502)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.723. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Crew Instructions (§ 250.506)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.710. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Well-control Fluids, Equipment, and Operations (§ 250.514)

This section of the existing regulation requires that well-control fluids, equipment, and operations be designed, used, maintained and tested to control the well under foreseeable conditions. BSEE did not propose any changes to this section except proposing to remove paragraph (d) of the existing regulation and move its content to proposed § 250.720. BSEE received no substantive comments on this proposed revision and the final rule takes that action.

What BOP information must I submit? (§ 250.515)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.731 and 250.732. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Blowout Prevention Equipment (§ 250.516)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.730, 250.733, 250.734, 250.735, and 250.736. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Blowout Preventer System Tests, Inspections, and Maintenance (§ 250.517)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.711, 250.737, 250.738, 250.739, and 250.746. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Tubing and Wellhead Equipment (§§ 250.518—Completion Operations and 250.619—Workover Operations)

These sections of the existing regulation provide requirements for placement of tubing strings, periodic evaluation of casing subject to prolonged operations, and monitoring of casing pressure for completions and workovers, respectively. BSEE proposed to remove former paragraph (b) from both sections (and to redesignate the remaining paragraphs accordingly); and to add new paragraphs (e) and (f) to both sections. Those new paragraphs would apply to packers and bridge plugs and require adherence to newly incorporated API Spec. 11D1, *Packers and Bridge Plugs;* clarify criteria production packer setting depths; and require that an APM include a description of, and calculations for determining, the production packer setting depths. After consideration of comments on the proposed revisions, BSEE has removed former paragraphs (b) from both sections in the final rule; has included paragraph (f), as proposed, in both final sections; and has revised the proposed language in paragraph (e) of §§ 250.518 and 250.619, as discussed in the following responses and in part V.C of this document.

Comments Related to Proposed §§ 250.518 and 250.619—Packers and Bridge Plugs

Summary of comments: Certain commenters stated that compliance with API Spec. 11D1 should not be required for temporary packers and bridge plugs (*i.e.,* those used for well servicing). Commenters stressed that API Spec. 11D1 does not apply to temporary packers and bridge plugs.

Commenters also had concerns about the proposed requirements in §§ 250.518(e) and 250.619(e) for setting depth and location of the packers. For example, the commenters were concerned that the regulations could require setting the packers as close as possible to the perforated interval and within the cemented interval of the casing section.

One commenter asked BSEE to clarify whether the requirements in proposed §§ 250.518 and 250.619 would apply only to packers and bridge plugs installed after the rule takes effect, or whether they would also apply to packers and plugs already installed before the rules take effect.

- *Response:* BSEE agrees with the commenters that the API standard itself does not apply to temporary plugs and packers, and thus that these regulations should only require compliance with API Spec. 11D1 for permanent packers and bridge plugs. Accordingly, BSEE has revised the text in paragraphs (e)(1) of final §§ 250.518 and 250.619 to reflect that the requirement applies only to permanently installed packers and bridge plugs.

BSEE understands the concerns about the production packer setting requirements. However, BSEE wants to ensure that the packer is set as required in this section in order to help ensure long term equipment reliability. For example, setting a packer in a cemented interval will slow down deterioration that could occur in other settings and thus will prolong the effectiveness of the packer. Also, BSEE wants to ensure that the packer is not set too high, so that, if there is a problem with the packer in the well (*e.g.,* a leak), operators will have enough space above the packer to pump a sufficient volume of weighted fluid into the well to exert a hydrostatic force greater than the force created by the reservoir pressure below the packer. If there are any concerns about the specific packer setting depth in any given case, the operator may contact the appropriate District Manager for guidance.

Finally, BSEE agrees that final §§ 250.518 and 250.619 are applicable only to packers and bridge plugs installed after the effective date of the final rule, and they do not require removal and replacement of existing packers and bridge plugs already in use. We slightly revised final § 250.518(e) to further clarify that intent; no change to final § 250.619(e) is necessary since that language is already clear on this point.

Subpart F—Oil and Gas Well-Workover Operations

General Requirements (§ 250.600)

This section of the existing regulation requires workover operations to be conducted in a way that protects human and animal life, property, OCS natural resources, National security and the environment. BSEE proposed no changes to this section except proposing to add a requirement for operators to follow the applicable provisions of new subpart G (in addition to subpart F). BSEE received no substantive comments on this proposed revision, and the final rule adds the proposed language to final § 250.600.

Equipment Movement (§ 250.602)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.723. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Crew Instructions (§ 250.606)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.710. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Well-Control Fluids, Equipment, and Operations (§ 250.614)

BSEE proposed to remove paragraph (d) of this former section and to move it to proposed § 250.720. BSEE received no substantive comments on this provision of the proposed rule and the final rule takes that action.

What BOP information must I submit? (§ 250.615)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.731 and 250.732. BSEE received no comments on the proposed removal and reservation of this section, and the final rule makes that change.

Coiled Tubing and Snubbing Operations (§ 250.616)

This section of the existing regulation was entitled ''Blowout Prevention Equipment'' and provided criteria for design, use, maintenance, and testing of BOPs and related well-control equipment. BSEE proposed to re-title § 250.616 as ''Coiled tubing and snubbing operations,'' to remove paragraphs (a) through (e) of the former section, and to move the content of those sections to final §§ 250.730 and 250.733 through 250.736. BSEE also proposed to re-designate former paragraphs (f) through (h) as paragraphs (a) through (c) without changing the contents of those paragraphs. As proposed, redesignated paragraph (a) sets minimum requirements for coiled tubing equipment and operations; redesignated paragraph (b) sets certain requirements for BOP system components for workover operations with a tree in place; and redesignated paragraph (c) requires that an inside BOP or certain types of safety valves be maintained on the rig floor during workovers. BSEE received no substantive comments on this provision of the proposed rule and final § 250.616 includes the proposed changes without additional revision.

Blowout Preventer System Testing, Records, and Drills (§ 250.617)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed §§ 250.711, 250.737, and 250.746. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

What are my BOP inspection and maintenance requirements? (§ 250.618)

BSEE proposed to reserve and remove this section and to move the content of this former section to proposed § 250.739. BSEE received no comments on the proposed removal and reservation of this section, and the final rule takes that action.

Subpart G—Well Operations and Equipment

General Requirements

What operations and equipment does this subpart cover? (§ 250.700)

As provided for in the proposed rule, this new section explains that subpart G applies to drilling, completion, workover, and decommissioning activities and equipment. BSEE received no substantive comments on this provision of the proposed rule and has made no changes to the proposed language in the final rule.

May I use alternate procedures or equipment during operations? (§ 250.701)

May I obtain departures from these requirements? (§ 250.702)

As provided for in the proposed rule, §§ 250.701 and 250.702 add provisions to new Subpart G acknowledging operators' ability to request BSEE approval of alternative procedures or equipment and to request departures from operating requirements in accordance with existing §§ 250.141 and 250.142, respectively. BSEE has considered the comments submitted on these proposed sections, and as explained in the following responses, the final rule includes these sections without change.

Comments Related to Proposed §§ 250.701 and 250.702—Alternate Procedures or Equipment and Departures

Summary of comments: Multiple commenters raised concerns about such requests. In particular, some commenters claimed that some of BSEE's past decisions on alternatives and departure requests were not consistent across all districts.

Another commenter asserted that the proposed rule is unclear about when it would be appropriate for BSEE to allow a departure from the well operations and equipment regulations in subpart G. The commenter stated that the reasons for granting a departure are not specified in existing § 250.142 or proposed § 250.702, and that the existing and proposed regulatory language for departure requests does not specify that the operator must demonstrate that it will achieve at least the same level of safety and environmental protection as the regulation from which it wants to depart. The commenter recommended that BSEE remove the proposed and existing regulations for departures, unless BSEE can explain its reasons for allowing departures from the applicable drilling requirements, or why a departure should be allowed without requiring an adequate substitute for the relevant requirements. The same commenter suggested that existing § 250.408 and proposed § 250.701 provide an adequate option for operators to request approval to use alternative procedures in situations, such as technical innovations, where there is a beneficial reason to allow such alternatives, that must meet or exceed the requirements in the regulations. Other commenters also raised questions regarding contractor responsibilities.

• *Response:* BSEE and the operators need enough flexibility under these rules to reasonably accommodate a wide range of potential alternative compliance methods and departures. Requests to use alternate procedures or equipment must provide sufficient justification for BSEE to make a determination that the proposed alternatives provide a level of safety and environmental protection that equals or surpasses current requirements. With respect to requests for departures from operating requirements, BSEE does not specify the type of justification required because doing so could unnecessarily limit the submission of supporting documentation that could be pertinent under the various circumstances that might arise. Moreover, even though existing § 250.409 and proposed § 250.702 do not expressly require an operator seeking a departure to demonstrate that the operator can still achieve the same level of safety and environmental protection required by the rules, BSEE expects that any request for departure will include appropriate measures to ensure safety and environmental protection. Accordingly, BSEE has not made any changes to this provision in the final rule.

BSEE is aware of operator perceptions that some past decisions made by different Regions or Districts on alternative compliance or departure requests appeared to lack complete consistency. However, approval of an alternative compliance or departure request is largely dependent upon specific site conditions and operational parameters that can vary significantly, even for requests that otherwise seem similar on their face. Thus, some perceived inconsistent decisions are explainable in light of the different case-specific facts and circumstances. BSEE strives to ensure consistency in decision-making among all Regions and Districts, and BSEE is developing internal procedures to improve consistency. In any event, this commenter's concerns about consistency do not require any change to the regulations.

Regarding the concerns raised about contractor responsibilities, that issue is discussed in part VI.B.5 of this document.

What must I do to keep wells under control? (§ 250.703)

As provided for in the proposed rule, this new section is intended to clarify certain precautions required to ensure well control at all times. Paragraphs (a) through (f) of proposed § 250.703 are included in the final rule without change for the reasons discussed in the following responses to comments. Proposed paragraph (f) of this section would require the use of equipment that is appropriately designed, tested, and rated. However, as explained in the following responses to comments on this proposed section, paragraph (f) in the final rule has been revised to clarify that it applies to the ''maximum environmental and operational conditions'' (rather than the proposed ''most extreme conditions'') to which the equipment will be exposed.

Comments Related to Proposed § 250.703—General Well-Control Requirements

Summary of comments: One commenter asserted that the rules should focus on minimizing the volume of an influx to a well and should require better ways (such as Coriolis meters, additional sensors, and personnel training) to determine and recognize flow. This commenter described an alternative approach based on understanding and recognizing well characteristics. The commenter noted that some companies already routinely perform this type of work. The commenter suggested the following revisions to the proposed rule: (1) Providing more emphasis on accurately measuring flows to and from a well; (2) remedying the current lack of control devices/instrumentation installed with deep-water marine riser systems; (3) requiring well-specific/rig-specific training for personnel; and (4) requiring realistic well control modeling of the well systems.

• *Response:* This section of the final rule provides both specific and general performance-based parameters for keeping wells under control that are applicable to all types of wells and conditions. However, the listed parameters are not exclusive of other well control measures. This section requires operators to ''take the necessary precautions,'' not just the precautions listed in § 250.703, to control wells and to ''[u]se and maintain equipment and materials necessary to ensure the safety and protection of personnel . . . and the environment.'' BSEE did not prescribe specific technological requirements, including some of the equipment recommended by the commenter, because we do not want to limit the operators' options to ensure and improve safety. BSEE is directly involved with numerous research projects, and aware of others, involving technological advancements that could improve equipment and processes, including ways to better identify an influx to a well and to improve rig personnel situational knowledge. As more information on such advancements becomes available, BSEE may use that information to update the regulations, as appropriate, in separate rulemakings. As a result, no changes were made to the proposed rule in response to this comment.

Comments Related to Proposed § 250.703—Best Available and Safest Drilling Technology

Summary of comments: One commenter discussed concerns about the potential change in expectations for operations that could result from the absence of the phrase ''best available and safest drilling technology,'' which was contained in former § 250.401(a) but which was not in proposed § 250.703. Instead, proposed § 250.703(a) would require the operator to ''use recognized engineering practices that reduce risks to the lowest level practicable.'' The commenter recommended that BSEE include both phrases in the final, promulgated version of § 250.703.

• *Response:* BSEE does not agree that adding the phrase ''best available and safest drilling technology'' to § 250.703 is necessary. The BSEE Director, under authority delegated by the Secretary of the Interior, will determine when to apply BAST for specific technologies. In applying BAST, the BSEE Director will determine: When the failure of equipment would have a significant effect on safety, health, or the environment; the economic feasibility of the technology; if the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies; and whether requiring the use of BAST is practicable on existing operations.

In this rulemaking, BSEE is not undertaking a BAST determination with respect to any specific technology that may be utilized to satisfy the requirements of § 250.703. Moreover, the requirement to use recognized engineering practices is one broadly associated with processes and methods. In contrast, the BSEE's BAST authority focuses on technologies, rather than practices.

Comments Related to Proposed § 250.703(f)—Most Extreme Service Conditions

Summary of comments: Some commenters requested revisions to proposed § 250.703(f), which would require the use of equipment that ''has been designed, tested, and rated for the most extreme service conditions to which it will be exposed while in service.'' Commenters asserted that multiple extreme conditions are unlikely to occur simultaneously; thus, expected conditions based on engineering judgment would better represent the real world. The commenters stated that unnecessary over-design of equipment, which could result from the proposed language, could decrease overall system reliability and introduce additional risk. For example, the commenters noted that increased design loads for BOPs would lead to larger material forgings, adding to overall stresses and fatigue loads experienced by wellheads and casing strings.

Other commenters asserted that the proposed language regarding ''most extreme conditions'' is unclear, and recommended revising the regulation to use the term ''anticipated conditions'' instead. Some commenters also suggested that if BSEE believes extreme load survival is warranted for certain pieces of equipment, then BSEE should require extreme load survivability, and justify it, as a separate provision.

• *Response:* BSEE agrees that confusion could be created by the term ''most extreme conditions.'' Accordingly, BSEE has revised final § 250.703(f) by replacing ''most extreme service conditions to which it will be exposed'' with the phrase ''the maximum environmental and operational conditions to which it may be exposed.'' The latter phrase is derived from former § 250.417(a), which is now designated as § 250.713(a) in this final rule and which retains that phrase. Thus, industry is already familiar with the meaning of that language. BSEE intends that language to ensure that equipment used for operations is designed, tested, and rated for the most adverse weather and other conditions specific to the location in which it will be used and the well conditions to which it may be exposed. For example, equipment used in the GOM does not need to be designed, tested, and rated for Arctic conditions unless that equipment will be used in the Arctic. However, equipment used in the GOM does need to be designed, tested and rated for the possibility of extreme weather conditions, including hurricanes.

Rig Requirements

What instructions must be given to personnel engaged in well operations? (§ 250.710)

As provided for in the proposed rule, this new section requires personnel engaged in well operations to be instructed in safety requirements, possible hazards, and general safety considerations, as required by subpart S of part 250, prior to engaging in operations. Also as provided for in the proposed rule, this section clarifies that the well-control plan must contain instructions for personnel about the use of each well-control component of the BOP system, and must include procedures for shearing pipe and sealing the wellbore in the event of a well control or emergency situation before MASP conditions are exceeded. These changes will help establish better proficiency for personnel using well-control equipment.

After consideration of the comments submitted on this proposed section, BSEE included the proposed language for this new section in the final rule without change, except that final paragraph (a) includes minor revisions to the proposed language in order to clarify the intent of this paragraph that personnel must be instructed in hazards and safety requirements.

Comments Related to Proposed § 250.710(b)—Well and Rig Specific Training

Summary of comments: One commenter recommended that this section should place more emphasis on well and rig specific training for the crew. The commenter suggested that proposed § 250.710(b)—regarding the contents and use of well control plans—comes close to that goal. However, the commenter suggested that BSEE should go further, including requiring that personnel be fully informed of the characteristics of the well.

• *Response:* BSEE does not agree that the suggested changes to this section are necessary. The requirements of § 250.710(b) are intended to, and should be sufficient to, help ensure that rig personnel engaged in well operations are informed about their specific well-control duties and capable of performing them.

Comments Related to Proposed § 250.710(b)—Well-Control Plan

Summary of comments: Another commenter expressed general support for proposed § 250.710(b), but recommended that BSEE require that a well-control expert prepare the plan. This commenter also provided additional suggestions for what the plan should address, such as well-control measures using the primary rig, source control and containment equipment, and secondary relief rigs. The commenter also expressed concerns about the proposed requirement to post a copy of the well-control plan on the rig floor. The commenter noted that the plan can be a complex, lengthy, technical document, and thus recommended that a copy of the complete well control plan should be available on the rig floor for reference, and that a shorter version of the plan (with the key well-control steps) should be posted on the rig floor for quick reference.

• *Response:* BSEE does not agree that the changes suggested by the commenter are necessary. BSEE believes it is important that the completed well-control plan be available (*i.e.*, ''posted'') in the specific areas where the personnel doing the work can review and use it to confirm any pertinent details of their and other personnel's well-control duties. If only a summary of the plan were required to be posted, there would be some risk that the summary would omit key details of which rig personnel need to be aware.

In addition, BSEE does not believe that it is necessary for a well-control expert to draft the plan, as long as it describes the specific well-control actions that rig personnel need to take, and provides the other essential information that the personnel need to know, as specified in § 250.710(b). Nor is it necessary to include the additional information (*e.g.*, availability of SCCE or a secondary relief rig) suggested by the commenter; that information would be more appropriate for an Oil Spill Response Plan, but is not relevant to the well-control duties of the rig personnel.

What are the requirements for well-control drills? (§ 250.711)

As provided for in the proposed rule, this section consolidates requirements for well-control drills from various sections of the existing regulations (*i.e.*, §§ 250.462, 250.517, 250.617, 250.1707) and makes the requirements applicable to all drilling, completion, workover, and decommissioning operations covered under new subpart G. After consideration of the comments submitted on this proposed section, BSEE has included the proposed language in the final rule without change, except for a minor change to paragraph (a), as explained in the following response to comments and in part V.C of this document. This change to the proposed language of paragraph (a) will help establish better proficiency for personnel using well-control equipment.

Comments Related to Proposed § 250.711—Well-Control Drills

Summary of comments: Some commenters asserted that the proposed requirement is overly prescriptive. Some commenters were concerned about the stipulation that the same drill could not be repeated consecutively. They stated that the nature of drills is to reinforce learning objectives and it may be appropriate to repeat a drill until a successful outcome is achieved. They also noted that the drills should reflect the operation being conducted; certain operations continue over an extended period of time, and therefore it may be appropriate to repeat the drill for the ongoing operation. Also, certain drills should be repeated due to the criticality of upcoming operations.

One commenter recommended that the type of drills to be run should be recommended by a well-control expert and included in the written well-control plan. Also, this commenter stated that the operator should document lessons learned from drills as well as any need for additional or repeat training.

• *Response:* BSEE wants to ensure that all personnel complete drills involved with all relevant aspects of operations. However, BSEE recognizes that some drills may be more critical than others and should be done on a regular basis. Therefore, based on the comments received, BSEE has revised final § 250.711(a) to clarify that a particular drill cannot be run consecutively with the same crew. This change will help avoid overly narrow training for certain personnel and improve proficiency in well-control procedures by a broader set of rig personnel without unduly limiting the operator's discretion to schedule important drills.

BSEE agrees that it is useful for an operator to document any lessons learned from completed drills and that the operator should take appropriate steps to correct any deficiencies or other problems noted from past drills. For example, if the operator notes that certain personnel did not perform their duties correctly during a drill, it should consider scheduling extra drills involving those personnel and otherwise ensure that the personnel understand and can perform their specific duties, as described in the well-control plan. However, it is not necessary to add such specific, prescriptive requirements to the rule, because § 250.711(a) already imposes a responsibility on the operator to ensure that drills familiarize well operations personnel with their roles so that they can perform their well-control duties promptly and efficiently. BSEE believes that this performance-based requirement, allowing operators to decide the most effective ways to structure their drills, is appropriate given that drills may vary from rig-to-rig according to the specific rig's location and circumstances and the well conditions. However, if, as provided by § 250.711(c), BSEE orders a drill (in consultation with the operator's onsite representative) during an inspection, and BSEE observes any deficiencies, BSEE will notify the operator of any deficiencies and appropriate follow-up actions, if necessary. If appropriate, BSEE may also require additional drills during subsequent inspections.

BSEE expects the well-control plan and drills, as required by §§ 250.710 and 250.711, to function together as effective tools to help rig personnel understand and efficiently perform their well-control responsibilities and duties. Accordingly, except with regard to the revision described previously in § 240.711(a), no further revisions to final § 250.711 are needed.

What rig unit movements must I report? (§ 250.712)

As described in the proposed rule, this section includes language similar to former § 250.403 and adds several new requirements for reporting rig movements to BSEE. Paragraphs (a) and (b) of the final rule address rig movement reporting requirements for all rig units moving on and off locations. Paragraph (c) requires notifications to BSEE if a MODU or platform rig is to be warm or cold stacked on a lease, including information about where the rig is coming from, where it would be positioned, whether it would be manned or unmanned, and any changes in the stacking location. Paragraph (d) requires notification to the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig prior to resuming operations after stacking. Paragraph (e) requires notification to the District Manager if a drilling rig enters OCS waters as to where the drilling rig is coming from. Paragraph (f) clarifies that if the anticipated date for initially moving on or off location changes by more than 24 hours, an updated Rig Movement Notification Report (Form BSEE–0144) must be submitted to BSEE.

After consideration of the comments received, and as explained in the following responses to comments and in part V.C of this document, BSEE has made several revisions to the proposed language in this final rule.

Comments Related to Proposed § 250.712—Terminology

Summary of comments: A commenter noted that there were inconsistencies in BSEE's use of various terms for ''rig'' in this section and throughout the proposed rule. The commenter noted terms used in this section include: ''Barge,'' ''coiled tubing unit,'' ''drill ship,'' ''jackup,'' ''snubbing unit,'' ''semisubmersible,'' ''submersible,'' ''wire-line unit,'' ''rig,'' ''rig unit,'' ''MODU,'' ''platform rig,'' and ''drilling rig.'' The commenter stated that these terms do not seem to be used consistently.

- *Response:* Different sections of the regulations may have different requirements for specific types of rigs, and BSEE has used different terms to specify what rigs are covered by each specific section. In particular, proposed and final § 250.712 expressly require reporting of movements by rig units, including MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. As a result, no changes to the rig terminology are necessary in the final rule. If any operator is unsure as to whether a particular section of the rules applies to a particular unit, the operator may contact the District Manager for assistance. If future experience with these final rules indicates that further guidance is needed on the meaning of any terms, BSEE may issue appropriate guidance or amend the regulations at that time.

Comments Related to Proposed § 250.712(a)—72-Hour Rig Movement Notification

Summary of comments: Several commenters raised concerns that the requirement in proposed § 250.712(a)(2) to notify the District Manager 72 hours before the planned movement of a rig—as compared to the longstanding requirement for 24-hour advance notification under former § 250.403(a)—will result in many inaccurate estimates of rig moves, given the potential for plans and schedules to change. Such changes are likely to result in multiple reporting adjustments being submitted to BSEE. Another commenter stated that the 72-hour notice requirement would be cumbersome and expensive for wireline and coiled tubing units.

- *Response:* BSEE agrees with commenters that the proposed 72-hour notice requirement may result in additional revisions to the submitted form, due to the possibility of frequent adjustments to the rig movement schedule over that period. A 24-hour notice requirement would provide a better, more reliable indication of when a rig will actually move and will minimize the need for revisions to previous notifications. Accordingly, the final rule retains the requirement of 24 hours, which was in the pre-existing regulation.

Comments Related to Proposed § 250.712(c)—Stacking of Rigs

Summary of comments: A commenter recommended that BSEE should include an ''escape clause'' under proposed § 250.712(c) so that operators who have not expressly provided permission for stacking a MODU on their lease would not be required to provide the specified information to BSEE.

- *Response:* BSEE does not believe that it is necessary to change the proposed language. BSEE intends that the responsibility for reporting the rig movement under this provision falls on the operator or lessee on the lease where the rig is working, not the operator or lessee where the rig is being moved to for stacking. Thus, if a lessee or operator has not given permission for another operator's MODU or platform rig to be stacked on its lease, the operator/lessee who holds the lease would not be required to provide the information to BSEE, as the commenter suggested.

Comments Related to Proposed § 250.712(d)—Notification of Construction, Repairs, or Modifications

Summary of comments: Regarding proposed § 250.712(d)—requiring notification of repairs or modifications to the drilling package for stacked units—a commenter suggested that BSEE should not assume an operator has stacked a rig on the operator's location, but rather should want to know if any stacked rig returns to operation and what was done to it prior to the commencement of operations. The rig may not be resuming operations for the operator who held the contract when it was moved. Another commenter requested that BSEE define the components of the ''drilling package'' and that, since equipment repairs are performed to return the equipment back to specification, the requirement to report repairs should be removed. A commenter stated that the requirement to notify the District Manager of ''any'' construction, repairs or modifications associated with the drilling package is ambiguous.

- *Response:* The information required by this section is necessary for planning and response purposes, including planning for possible inspections. The term ''drilling package'' is a commonly understood industry term and does not require further definition. BSEE intends that ''any'' construction, repairs, or modifications should be reported. If repairs or modifications were made to the drilling package, BSEE could need that information to plan and conduct inspections and perform additional reviews to ensure the repaired or modified equipment is used as intended. Although BSEE cannot predict in advance all potential types of repairs or modifications that may arise, BSEE expects a rule of reason, and does not expect every trivial, de minimis, repair (*e.g.*, replacing a loose screw) to be reported.

Comments Related to Proposed § 250.712(e)—Rig Entering OCS Waters

Summary of comments: A commenter asserted that paragraph (e) assumes the operator has the rig under contract when it enters OCS waters. The commenter suggested that the requirement instead be keyed to when a rig is first utilized for well operations after coming from an overseas location.

• *Response:* BSEE disagrees. BSEE expects an operator that has a contract on a rig coming from overseas to make the notification upon entry of the rig into U.S. waters, so that BSEE has an opportunity to inspect or otherwise determine that the rig is suitable, before the rig is first utilized on the OCS. Operators should be aware if its contract rig is entering OCS waters and where it is coming from.

What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations? (§ 250.713)

As provided for in the proposed rule, this section includes MODU requirements (*e.g.*, fitness and foundation requirements) from former § 250.417, and makes the former requirements applicable to all operations covered under subpart G. Paragraph (g) of the final rule also codifies certain monitoring requirements previously discussed in BSEE NTL 2009–G02, *Ocean Current Monitoring.* This final section is revised from the proposed rule as discussed in the comment responses for this section and part V.C of this document.

Comments Related to Proposed § 250.713—Platform Types and USCG

Summary of comments: One commenter suggested that this section should also apply to other types of platforms, including multi-purpose service vessels. Another commenter recommended that BSEE coordinate with United States Coast Guard (USCG) regarding specific operating criteria used to analyze structural pipe on deepwater wells and take this opportunity to set uniform standards across the OCS. A commenter suggested adding the USCG to the provision under proposed § 250.713(d) regarding documentation of operational limits imposed by a classification society.

• *Response:* Although there may be some benefit to applying these requirements to other types of platforms, BSEE does not currently have enough data to make that determination. BSEE will need more data, and more research needs to be conducted, to justify expanding the scope of this section to other vessels and rigs. Similarly, BSEE does not have enough information at this time to proceed with the commenter's suggestion that we set specific criteria for analyzing structural pipe on deepwater wells.

In addition, BSEE would need to gather more information and to further consult with USCG before deciding whether to add USCG to the § 250.713(d) requirement for providing documentation on operational limits. BSEE may consider addressing these issues in separate rulemakings at a later date. In the meantime, BSEE will continue its close coordination with USCG in all matters involving BSEE and USCG responsibilities.

Comments Related to Proposed § 250.713—Terminology

Summary of comments: Another commenter asserted that the use of inconsistent terminology for ''rigs'' (*e.g.*, unit, rig unit) in this section may create confusion and recommended that BSEE review the Part 250 regulations for how the various terms referring to rigs are used and then include appropriate definitions.

• *Response:* Different sections of the regulations may have different requirements for specific types of rigs, and BSEE has used different terms to specify what rigs are covered by each specific section. However, BSEE agrees with the suggestion that the uses of various terms for rigs in this specific section could cause some confusion. Accordingly, BSEE made minor changes to this section to improve consistency between rig terms (*e.g.*, we replaced ''unit'' with ''MODU'' in final § 250.713(a)). The suggestion that BSEE review all of part 250 regarding the terminology for rigs falls outside the scope of this rulemaking. BSEE may review all of part 250 for this purpose at a later date.

Comments Related to Proposed § 250.713(a)—Fitness Requirements

Summary of comments: A commenter suggested that, under proposed § 250.713(a), the requirement to provide information demonstrating the unit's capability to perform under the most extreme conditions (including the minimum air gap for the hurricane season) should apply only if appropriate. This commenter noted that dynamically positioned rigs, MODUs and multi-purpose supply vessels typically do not stay on location during hurricane season.

Another commenter stated that the requirement to collect and submit environmental data to the District Manager after an APD/APM is approved would not benefit the MODU or lift boat that is already on location under the approved permit and that is collecting the data, and the MODU or lift boat could be at risk if it were truly ''unsuitable'' for the site conditions where it is gathering the data. The commenter recommended that a metocean specialist assess the suitability of the MODU or lift boat for the location, applying conservative environmental criteria. If there is uncertainty in the metocean criteria that cannot be resolved, the environmental data should be gathered before mobilizing a MODU or lift boat to the location.

• *Response:* BSEE agrees that the requirement to submit information on the most extreme environmental conditions that the unit is designed to withstand only requires information regarding the minimum air gap where that is a relevant factor in the unit's design. For example, not all MODUs have or require an air gap (*e.g.*, drillships). However, BSEE does not believe it is necessary to expressly add such a limitation in § 250.713(a), since it is already clearly implied by the language stating that the operator is only required to submit information about the most extreme conditions the ''MODU is designed to withstand.''

BSEE agrees that environmental data should be gathered before mobilizing a MODU to location, although no change to the regulatory text is required to make that point. The requirements in § 250.713(a) have been in place—in former § 250.417(a)—for years and BSEE is not aware of any problems occurring because a unit was onsite before the data was gathered and submitted. Nor does BSEE believe that it is necessary to require a metocean expert to assess the suitability of the unit for the environmental conditions under this longstanding provision. Furthermore, the District Manager has the authority to revoke approval of the permit if data collected during operations shows the MODU cannot perform at the proposed location. This will help BSEE ensure that the MODU proposed for OCS operations is appropriate for the specific location.

Comments Related to Proposed § 250.713(b)—Foundation Requirements

Summary of comments: One commenter asserted that § 250.713(b)—regarding foundation requirements for MODUs and lift boats—should apply only to bottom-supported MODUs or lift boats, where a loss of foundation is catastrophic, and that BSEE should exclude moored MODUs from this requirement. Another commenter suggested adding text to this section to state that the District Manager may accept lower-bound and upper-bound soil properties, based on regional soil data and developed by a knowledgeable geotechnical engineer, in lieu of the requirement to submit information on site-specific soil conditions.

• *Response:* BSEE agrees with the comment that paragraph (b) should apply only to bottom-founded MODUs. Accordingly, BSEE revised § 250.713(b) to clarify that this provision requires submittal of information showing that site-specific soil and oceanographic conditions are capable of supporting the proposed bottom-founded MODUs. (In addition, as explained later, BSEE has removed lift boats altogether from this section of the final rule.)

However, BSEE does not agree that regional soil data should be allowed in place of site-specific soil data. The purpose of the soil data requirement in § 250.713(b) is to ensure that the foundation at the specific site is actually capable of supporting a bottom-founded MODU, and regional soil data may not be sufficient to demonstrate the suitability of the soil at that particular site.

Comments Related to Proposed § 250.713(c)—Frontier Areas

Summary of comments: One commenter asserted that proposed § 250.713(c) (requiring information about units in frontier areas) and (f) (availability of units for inspection) should not apply to lift boats. The commenter stated that lift boats are classified as offshore support vessels and are regulated by the USCG.

• *Response:* Commenters raised several jurisdictional and technical concerns regarding the applicability of this section to lift boats. For example, some of the information, or access to information, required by this section may not be available or pertinent for some lift boats. Accordingly, BSEE revised the final rule by deleting all references to lift boats in § 250.713.

Comments Related to Proposed § 250.713(e)—Contingency Plans

Summary of comments: Another commenter recommended adding provisions to § 250.713(e), which requires contingency plans for dynamically positioned MODUs to move offsite in emergencies, in order to ensure that the operator has plans to secure the well during planned suspensions.

• *Response:* Requirements for securing a well during any interruption, including suspensions, are adequately covered under final § 250.720. Therefore, no changes to § 250.713(e) are necessary in this regard.

Do I have to develop a dropped objects plan? (§ 250.714)

As provided for in the proposed rule, this new section codifies some of the language from BSEE NTL 2009–G36, *Using Alternate Compliance in Safety Systems for Subsea Production Operations,* and is intended to help avoid prolonged damage to subsea infrastructure and to assist operators and BSEE in responding to a dropped object. This section also requires an operator to develop a dropped objects plan and specifies certain information and procedures that must be included in the plan. This final section is revised from the proposed rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.714(c)—Modeling a Dropped Object's Path

Summary of comments: One comment on proposed § 250.714(c)—requiring floating rigs in areas with subsea infrastructure to model a dropped object's path—asserted that modeling the path does not significantly reduce the risk associated with a dropped object.

With regard to proposed § 250.714(e)—requiring operators to include in their dropped objects plan ''any additional information required by the District Manager''—one commenter recommended that BSEE should limit requests for additional information to ''information needed to ensure protection of onsite personnel or the environment.'' Another commenter asserted that § 250.714(e) is ambiguous and that BSEE should clarify it. Another commenter observed that companies should have simultaneous operations (SIMOPS) procedures in place.

• *Response:* BSEE does not agree that there is no potential benefit to modeling a dropped object's path. With the continuing expansion of subsea infrastructure, BSEE determined that it is important for operators to be aware of, and plan for, the potential impacts of a dropped object. Having a dropped object plan helps increase such awareness and will help operators, and BSEE, to identify impacted infrastructure in order to improve responses to a dropped object.

Section 250.714(e) is intended to give District Managers the necessary flexibility and discretion to require information as needed in specific cases to fulfill the purposes of the regulation. However, BSEE has further clarified final § 250.714(e), by stating that a District Manager may require additional information as appropriate to clarify, update, or evaluate a dropped objects plan. Thus, the District Manager may require additional information regarding dropped objects on a case-by-case basis, based on unique site or well conditions.

BSEE currently does not have enough information about SIMOPS to warrant including such a requirement in this final rule. However, BSEE agrees that SIMOPS may be a tool that operators should consider when multiple operations are being conducted at the same time or in conjunction with each other. If research or studies or other information about SIMOPS become available in the future that warrant further revision of this regulation, BSEE may propose such a revision in a future rulemaking.

Do I need a global positioning system (GPS) for all MODUs? (§ 250.715)

As provided for in the proposed rule, this new section codifies existing BSEE NTL 2013–G01, *Global Positioning System (GPS) for Mobile Offshore Drilling Units (MODUs).* The GPS requirements for MODUs include: Providing a reliable means to monitor and track the unit's position and path in real-time if the unit moves from its location during a severe storm; installing and protecting the GPS equipment to minimize the risk of the system being disabled; having the capability of transmitting data for at least 7 days after a storm has passed; and providing BSEE with real-time access to the unit's GPS location data. This final section is revised from the proposed rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.715—Terminology

Summary of comments: A commenter raised concern about apparent inconsistencies in the use of terminology related to rigs in this section. The commenter pointed out that in the proposed rule this section referred to ''MODUs and jack-ups,'' ''jack-up and moored MODUs,'' ''moored MODU or jack-up,'' and ''Rig/facility/platform.'' In addition, the caption for this section implies that a jack-up is not a MODU.

- *Response:* BSEE agrees that the proposed rule's terminology concerning rigs in this section might cause some confusion. BSEE made some minor changes to this section in the final rule to improve consistency between rig terms. For example, BSEE has revised the title of this section to ''Do I need a GPS for all MODUs?'' and in final § 250.715(a), we have replaced ''jack-up and moored MODU'' with ''MODU.''

Comments Related to Proposed § 250.715—Applicability

Summary of comments: A commenter suggested that this provision should be extended to all MODUs, including dynamically positioned MODUs, rather than just moored MODUs. All MODUs moved from the path of a storm should be tracked for emergencies.

- *Response:* BSEE agrees with the commenter that all MODUs should be tracked during severe storms, as required by § 250.715(e). In any event, as previously stated, BSEE has revised final § 250.715(a) by deleting the word ''moored.'' In addition, to avoid any potential confusion, BSEE revised the title of this section to refer to ''all MODUs.''

Comments Related to Proposed § 250.715(a)—GPS Monitoring and Tracking

Summary of comments: Another commenter recommended revising proposed § 250.715(a) by removing the phrase ''if the moored MODU or jack-up moves from its location during a severe storm.''

- *Response:* BSEE does not agree with the commenter's suggestion. The commenter provided no explanation for this recommendation. Operators and BSEE will need the GPS data, and thus all MODUs must possess GPS systems capable of providing such data to track units during severe storm events. Removing the phrase suggested by the commenter would require that the GPS systems also be able to monitor and track the unit when making normal rig moves under routine conditions. Although any GPS system that provides the tracking and monitoring data during a severe storm would be able to provide such data during a normal move, BSEE does not need access to such data and sees no need to require operators to have such a capability. BSEE is particularly concerned about MODUs that lose station-keeping or part moorings during storms. Thus, BSEE slightly revised the first sentence in this section to clarify that BSEE must have real-time access to GPS data prior to and during each hurricane season, consistent with the language in NTL 2013–G01 that this provision is codifying (see 80 FR 21519).

Well Operations

When and how must I secure a well? (§ 250.720)

As provided for in the proposed rule, this section consolidates requirements from various provisions of the existing regulation regarding how to secure a well whenever operations are interrupted. Paragraph (a) requires that the District Manager be notified when operations are interrupted and provides examples of events that would warrant interruption of operations (*e.g.,* any observed flow outside the well's casing). The requirement to notify the District Manager gives BSEE awareness of interrupted operations and an opportunity for an appropriate response. Paragraph (a) also requires a negative pressure test to ensure wellbore and barrier integrity before removing a subsea BOP stack or surface BOP stack on a mudline suspension well. Paragraph (a)(2) clarifies that if there is not enough time to install the required barriers or other special circumstances occur, the District Manager may approve alternate procedures in accordance with § 250.141. Paragraph (b) of this section requires prior approval by the District Manager for displacement of kill-weight fluid from a wellbore and/or riser and specifies the information that must be included in an APD or APM to seek such approval. This section is unchanged from the proposed rule.

Comments Related to Proposed § 250.720(a)—Testing and Verifying Barriers

Summary of comments: Some commenters recommended that the barriers required by proposed § 250.720(a), when operations are interrupted be tested and verified as effective by an engineer before the BOP is removed. One commenter also recommended that the regulation clearly require that barriers be installed prior to removing a BOP. This commenter asserted that it appears this was intended, but that the regulatory language would benefit from additional clarification, including clarifying that it applies when a BOP is removed but the rig has not yet moved off location.

- *Response:* BSEE does not agree with the suggested changes. It is not necessary to add a requirement to this paragraph for a PE verification of a barrier's effectiveness, given that the barriers must be tested, according to § 250.720(b)(2), to ensure integrity before moving off the well. Nor is any change needed to clarify that the barriers must be installed and tested before moving off location; in fact, § 250.720(a) already expressly requires that two independent barriers must be installed ''[b]efore moving off the well,'' and § 250.720(b) effectively requires that the barriers be tested before removing mud from the riser in preparation for moving off the well.

What are the requirements for pressure testing casing and liners? (§ 250.721)

As provided for in the proposed rule, this section incorporates and revises certain requirements from former §§ 250.423 and 250.425 for pressure testing casing and liners. Among other things, final § 250.721 increases the minimum test pressure specification for conductor casing (excluding subsea wellheads) from 200 psi, as under the former regulations, to 250 psi; requires operators to test each drilling liner and liner-lap before further operations are continued in the well and provides the parameters for such tests; clarifies that the District Manager may approve or require other casing test pressures as appropriate to ensure casing integrity; requires that operators follow additional pressure test procedures when they plan to produce a well that is fully cased and cemented or is an open-hole completion; requires a PE certification of plans to provide a proper seal if there is an unsatisfactory pressure test; and requires a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems. This final section is revised from the proposed rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.721—Monitoring and Verification

Summary of comments: A general comment on this section asserted that BSEE should consider improvements to the monitoring and verification of makeup/torqueing of casing/tubular connections, under this section and § 250.423(c). Similarly, another commenter stated that BSEE should focus on ensuring integrity of the casing string and recommended doing so by linking minimum casing test pressure to formation integrity pressure.

- *Response:* BSEE does not agree that these suggested changes are necessary to ensure proper installation of casing and tubing. BSEE already requires a pressure test on the casing seal assembly under former § 250.423(b)(3)—now § 250.423(c)—and submittal to BSEE of both the test procedures and test results, in order to verify the integrity of the casing and connections. There is no need for additional language to confirm these results.

Comments Related to Proposed § 250.721(a) Through (c)—Liner Lap Testing

Summary of comments: Multiple commenters asserted that testing of the liner-lap, as specified in proposed § 250.721(a) through (c), is not possible. The commenters recommended instead that the liner-top be tested to confirm integrity of the casing.

• *Response:* BSEE agrees with the comment that the liner lap cannot be tested as proposed, since the liner-lap will not actually respond to the pressure from such a test, while the liner-top will respond to that pressure. Accordingly, testing of the liner-top is sufficient to demonstrate the integrity of the well, and BSEE has revised final § 250.721(b) and (c) by substituting ''liner-top'' for ''liner-laps'' with regard to the testing required to confirm integrity.

Comments Related to Proposed § 250.721(a)—Testing of Surface, Intermediate and Production Casing

Summary of comments: Another commenter stated that under proposed § 250.721(a)(3)—regarding testing of surface, intermediate and production casing—BSEE should allow operators to test the casing to either 70 percent of the casing's minimum internal yield pressure (as proposed) or to MAWHP plus 500 psi, in order to avoid putting unnecessary loads on the casing or cement.

A commenter claimed that there is no engineering basis for the requirement in proposed § 250.721(b) to test formation integrity at the liner shoe, if the liner will not be exposed to that amount of pressure. The commenter claimed, for example, that casing shoes set in salt are not exposed to such pressures.

• *Response:* BSEE does not agree that the suggested changes are needed or appropriate. The requirement for testing casing to 70 percent of its minimum internal yield pressure is a longstanding requirement, formerly in § 250.423(a)(3), and BSEE is not aware of any significant problems or concerns with testing to that limit. If an operator has any concerns with the testing procedures in a specific case, however, the operator may request, and the District Manager may approve, other casing test pressures on a case-by-case basis under § 250.721(d).

For the same reasons, BSEE does not agree that the suggested changes to § 250.721(b) are warranted. That testing requirement has been in place for many years (formerly in § 250.425(a) and (b)) and BSEE is not aware of industry raising any concerns with implementing that requirement. In any event, any operator that wants to seek approval of an alternative test pressure under § 250.721(d) in a specific case may do so.

Comments Related to Proposed § 250.721(e)

Summary of comments: A commenter raised concerns about proposed § 250.721(e)—regarding pressure testing for a well that is planned for production—stating that the proposed language to ''pressure test the entire well to maximum anticipated shut-in tubing pressure'' is not clearly defined. The commenter asserted that the text is not clear as to whether the ''anticipated shut-in tubing pressure'' is the pressure with a full column of hydrocarbons or the pressure after perforating with an underbalanced fluid. The commenter claimed that this ambiguity would make implementing this requirement problematic when the fluid in the well at the time of pressure testing is of a different density than the planned completion fluid. The commenter described various risks associated with this situation and suggested that BSEE clarify that the testing pressure must not ''exceed 70 percent of the burst rating limit of the weakest component.''

Another commenter stated that the existing regulations on testing (§ 250.423) are fit-for purpose, and that industry's long standing practice to test casing to maximum values only with a technical reason for doing so is sufficient. The commenter stated that testing to maximum anticipated shut-in tubing pressure may do unnecessary harm to the cement integrity.

• *Response:* BSEE agrees that continually pressure testing to the maximum anticipated shut-in tubing pressure may put additional stresses on the cement and thus potentially affect cement integrity. Therefore, as suggested by one of the commenters, BSEE has revised final § 250.721(e) by inserting the phrase ''but not to exceed 70 percent of the burst rating limit of the weakest component'' to help ensure long term cement integrity. In addition, as provided by final § 250.721(d), if an operator has other concerns about casing test pressures, it may seek approval from the District Manager or Regional Supervisor for alternative test pressures on a case-by-case basis.

Comments Related to Proposed § 250.721(f)—Pressure Testing Before Resuming Operations

Summary of comments: One commenter recommended that BSEE should revise § 250.721(f)—requiring pressure testing of a well before resuming operations—to require operators to run pressure tests long enough to stabilize the pressure and to hold a constant pressure for 30 minutes.

• *Response:* BSEE does not agree that holding a constant pressure for 30 minutes is necessary to demonstrate sufficient stability to resume operations. Due to well parameters such as, but not limited to, thermal effects, fluid compressibility, fluid characteristics, and environmental conditions, holding a constant pressure for 30 minutes may not be possible. The proposed requirement that—if the pressure declines more than 10 percent in 30 minutes—the District Manager must approve a PE-certified plan to resolve the pressure issue is sufficient to ensure that the well is fit to be operated.

Comments Related to Proposed § 250.721(g)—Negative Pressure Test

Summary of comments: BSEE received multiple comments on proposed § 250.721(g), which addressed negative pressure testing of wells with subsea BOP stacks or mudline suspension systems. Commenters asserted that the negative pressure tests under § 250.721(g)(1) and (3), should only be required if hydrocarbons are present. Commenters also recommended that § 250.721(g) require two barriers only if hydrocarbons are present.

• *Response:* BSEE disagrees with the comments about testing the barriers only if there are hydrocarbons present. BSEE determined that ensuring barrier integrity and well stability by performing the required tests is important, even if hydrocarbons are not present at the time, because geological conditions (*e.g.,* fluid migration) may exist that could subsequently result in hydrocarbons entering the well if the barriers are not effective. Thus, testing the barriers' effectiveness under such conditions will help ensure that hydrocarbons will not enter the well at a later date.

What are the requirements for prolonged operations in a well? (§ 250.722)

As provided for in the proposed rule, this section consolidates and clarifies various sections of the existing regulations that established requirements for well integrity for operations continuing longer than 30 days from a previous casing or liner test. If well integrity has deteriorated to a level below minimum safety factors, this section requires repairs or installation of additional casing and subsequent pressure testing, as approved by the District Manager. As discussed in the comment responses for this section and in part V.C. of this document, BSEE has revised the language of proposed paragraph (a) in the final rule.

Comments Related to Proposed § 250.722—Introductory Paragraph

Summary of comments: BSEE received a comment on the introductory paragraph of § 250.722, which specifies actions that must be taken if wellbore operations continue more than 30 days after the previous pressure test. The commenter suggested that the introductory text be revised to include ''or independent third-party review of the well's casing or liner'' as a condition of timing for performing the requirements in this section.

• *Response:* BSEE did not revise this section based on the comment. It is not clear from the comment how the independent third-party would review the well's casing or liner.

Comments Related to Proposed § 250.722(a)—Prolonged Well Operations

Summary of comments: Other commenters raised concerns with proposed § 250.722(a), which requires that operations stop as soon as practicable, and that the operator must: Evaluate the effects of prolonged operations using a pressure test, caliper or imaging tool; and report the results, including calculations showing the well's integrity is above minimal safety factors, to the District Manager. Commenters asserted that calculations that show a well's integrity is above the minimum safety factors cannot be performed for a casing pressure test, and thus recommended revisions to § 250.722(a)(2) to clarify that the report must include calculations showing that the well's integrity is above the minimum safety factors only if an imaging tool or caliper is used.

• *Response:* BSEE agrees with the comment that calculations that show a well's integrity cannot be performed for a casing pressure test. Accordingly, BSEE has revised final § 250.722(a)(2) to say that the report must include calculations that show the well's integrity is above the minimum safety factors if an imaging tool or caliper is used.

What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow? (§ 250.723)

As provided for in the proposed rule, this section consolidates and revises requirements from several former sections (*i.e.,* §§ 250.406, 250.518(b), 250.619(b)) regarding additional safety measures for operations on a platform that has a producing well or other hydrocarbon flow. Among other requirements, this section requires the installation of an emergency shutdown station, for the production system, near the rig operator's console. This provision helps ensure that rig units would be able to shut-in the production system of the host facility. For the reasons discussed in the following comment responses, the final rule makes no changes to the proposed rule in regard to this section.

Comments Related to Proposed § 250.723—Terminology

Summary of comments: A commenter noted that there are apparent inconsistencies in BSEE's use of terms for ''rig'' in this section. The commenter noted terms used in this section include: ''coiled tubing unit,'' ''lift boat,'' ''drill ship,'' ''jackup,'' ''snubbing unit,'' ''wire-line unit,'' ''rig unit,'' and ''MODU.'' However, the commenter provided no specific suggestions for addressing this issue.

• *Response:* For the reasons stated in response to similar comments on proposed § 250.712, BSEE has determined that no changes to the terminology in this section are necessary.

Comments Related to Proposed § 250.723—Definition of ''Platform''

Summary of comments: Another commenter stated that the term ''platform,'' which is mentioned in this section's heading, is not defined in part 250, and that facilities or rigs may be built and operated on gravel islands or installed on bottom-founded offshore structures. The commenter recommended that BSEE develop and add a new definition of ''platform,'' including facilities on gravel islands or bottom-founded structures, to § 250.105.

• *Response:* This comment recommends adding a new provision that was not in the proposed rule, and the commenter did not suggest a specific definition for BSEE to consider. BSEE has decided that it is not appropriate to include such a new definition in this final rule. Various sections of BSEE's current regulations have long used the term ''platform'' (or similar terms), including former § 250.406, on which final § 250.723 is partially based, and BSEE is unaware of any significant difficulties by regulated entities in understanding that term in connection with that former section. Moreover, since that term is used in somewhat different contexts in different provisions, a single definition of that term might not be suitable for use in every context.[14]

Comments Related to Proposed § 250.723(c)—Lift Boats

Summary of comments: A commenter suggested that BSEE not include lift boats in § 250.723(c)(3), which requires shut-in of producible wells when a MODU or lift boat moves within 500 feet of the platform. The commenter observed that lift boats are self-powered motor vessels, which are more maneuverable than, and not comparable to, a MODU that is towed on location.

• *Response:* BSEE disagrees with the comment about removing lift boats from paragraph (c)(3). Even though a lift boat may be more maneuverable than a MODU, care must still be taken when any large object, such as a lift boat, undertakes any movement near a well with producing hydrocarbons. The risk of a collision or other incident that could trigger a well-control event cannot be eliminated simply because the moving object may be relatively maneuverable.

What are the real-time monitoring requirements? (§ 250.724)

As described in the proposed rule, this new section includes requirements for gathering and monitoring real-time well data. The proposed section has been revised in the final rule as discussed in the comment responses for this section and in part V.B.4 of this document. Proposed paragraph (a) has been revised to clarify that it requires using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the BOP control system, the well's fluid handling system on the rig, and the well's downhole conditions. Proposed paragraph (b) has been revised to describe some of the required RTM operational capabilities and procedures. Proposed paragraph (c) has been revised to require that an operator develop and implement an RTM plan, to specify certain information that must be included in the plan, and to require that BSEE be provided with access to the plan, and to RTM data, upon request.

[14] 14 For example, BSEE has already proposed adding a definition of ''fixed platform'' to § 250.105, for use in connection with proposed amendments to § 250.108. (*See* 80 FR 34113 (June 15, 2015).) While that proposed definition would be appropriate for use under the specific circumstances applicable to the proposed amendments to § 250.108 (*see id.* at 31446), it might not be as appropriate for defining similar terms in other sections.

Comments Related to Proposed § 250.724—Claims That the RTM Requirements are Premature

Summary of comments: Some comments asserted that any RTM rule would be premature until after studies and research on the application of such monitoring and analysis to offshore oil and gas operations is complete. Specifically, some comments suggested that BSEE take no final action on the RTM regulation until after the National Academy of Sciences (NAS) Transportation Research Board completes a study on RTM, commissioned by BSEE, and releases its final report.

- *Response:* RTM is not a novel concept or technology, and it is currently widely used in many industrial applications, including offshore oil and gas development. Several of the industry commenters stated that they already have RTM plans and use RTM systems in their offshore operations, and acknowledged the value of such programs. In addition, based on regular interaction with operators, BSEE is aware that many other operators already use RTM capabilities to monitor certain aspects of their operations. Thus, BSEE does not agree that it is appropriate to delay promulgation of the RTM requirements in this final rule until after the completion of the NAS Report, especially since compliance with the RTM requirements will not be required until three years after publication of the final rule, and the NAS report is currently scheduled to be completed in May 2016. (More information on the NAS study is available at: *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Projects/Project-740/*.) BSEE will carefully consider the NAS report when it is issued, and if BSEE concludes that the report warrants any revisions to these final regulations, BSEE may propose such changes in a separate rulemaking.

Comments Related to Proposed § 250.724—Concerns About RTM Transmission

Summary of comments: Some comments raised concerns regarding the possibility that the transmittal of RTM to an onshore location could provide another opportunity for data system attacks, and that this increases the need for more cyber security. In addition, some comments asserted that the proposal would increase problems with data retention and data quality (*e.g.*, availability of bandwidth and upload time), although no specifics were provided in those comments.

- *Response:* Concerns about cyber security, data retention, and data quality have been and will continue to be an issue for all regulatory programs that require electronic transmission or storage of data. However, much rig-based data has long been, and will continue to be, transferred to shore without regard to the proposed RTM requirements and, in many cases, without being required by any regulation. Many effective measures to address cyber security (*e.g.*, access controls, encryption, firewalls, intrusion detection), data retention, and data quality issues are available, and BSEE is confident that the offshore oil and gas industry is aware of and frequently uses such measures. Accordingly, such concerns do not justify foregoing the expected benefits of the RTM requirements of this final rule.

Comments Related to Proposed § 250.724—Concerns About Compliance Timing

Summary of comments: Some comments requested that, in lieu of the proposed requirements, BSEE give operators 5 years from publication of the final rule to address BOPs in RTM plans.

- *Response:* Those comments did not include any specific explanation or support for the requested 5-year period for incorporating BOP RTM data in such RTM plans. BSEE has reviewed the relevant comments and supporting information, and determined that 3 years will provide sufficient time to implement the final RTM requirements for all of the specified data, including data regarding the BOP control system, as proposed. Based upon public comments and prior consultation with industry, BSEE believes that many operators have already implemented some form of RTM for at least some rig equipment and operations (*e.g.*, drilling and fluid handling systems); thus, modifying (if necessary) such existing RTM programs to include the data specified in § 250.724(a), including BOP data, can be reasonably accomplished within 3 years.

Comments Related to Proposed § 250.724(a)—Scope of Data To Be Monitored

Summary of comments: Some comments questioned what was meant by the proposed requirement that the operator's RTM system must be capable of monitoring ''all aspects of'' the BOP control system, the well's fluid handling system, and the well's downhole conditions with any installed bottom hole assembly tools.

- *Response:* For clarity and to avoid any potential confusion, BSEE deleted the phrase ''all aspects of'' from final § 250.724(a), which now requires that the RTM system be capable of ''recording, storing, labeling, and transmitting data regarding'' the ''BOP control system data . . .,'' the ''well's fluid handling system . . .,'' and the ''well's downhole conditions . . . .''

Comments Related to Proposed § 250.724(b)—Concerns About RTM and Decision-Making

Summary of comments: Many commenters asserted that the proposed RTM requirements would lead to an erosion of authority of, or shifting operational decision-making away from, the rig-site personnel. In particular, some commenters claimed that the requirement in proposed § 250.724(b)(4) that RTM data be ''immediately transmitted'' to onshore personnel who must be in ''continuous contact'' with rig personnel implied that BSEE expected onshore personnel to be able to override rig personnel in making key operational decisions based on the RTM data. The commenters asserted that such intervention could be detrimental to the rig personnel's performance of their operational duties, as well as their sense of accountability, and thus could actually inhibit their responses to unusual data and otherwise degrade safety and environmental protection.

- *Response:* The proposed rule did not intend to, and the final rule does not, contribute to an erosion of authority of, or shifting of operational decision-making away from, the rig-site personnel. The proposed requirement was intended only to ensure that RTM data is transmitted onshore and that onshore personnel who have the ability to monitor the data and contact rig personnel in the event that unusual data warrants discussion with and potential evaluation by rig personnel. (See 80 FR 21520.) BSEE intended the proposed rule to ensure that onshore personnel could serve as ''another set of eyes'' to monitor the data and potentially to assist rig personnel in performing their duties, but not to override the key onsite decision makers or interfere with rig personnel performing their onsite duties.

However, to avoid any confusion in this regard, BSEE has revised final § 250.724(b) to address the commenters' concerns, while staying true to BSEE's original intent. In particular, we have replaced the proposed requirement to ''immediately transmit'' the RTM data to the onshore location with a requirement to transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission. In addition, we have replaced the proposed reference to onshore personnel ''who must be in continuous contact with rig personnel'' with a new sentence requiring that ''[o]nshore personnel who monitor real-time data must have the capability to contact rig personnel during operations.''

Comments Related to Proposed § 250.724(b)—Concerns About RTM Interruptions

Summary of comments: A commenter suggested that the proposed requirement in § 250.724(b) regarding communications (continuous contact) between rig personnel and onshore personnel would result in a shutdown of operations at the rig in the event of any interruption, no matter how brief or inconsequential, to onshore-rig communications. The commenter asserted that such shutdowns, and subsequent restarting of operations, would be extremely costly and would create additional risks of malfunction during the shutdowns without any corresponding benefits. Another commenter also suggested that loss of RTM transmission to onshore should not result in a shutdown under proposed § 250.724(c).

• *Response:* Nothing in the proposed rule suggested that an operator must automatically shutdown, or that BSEE would necessarily order a shutdown of operations due to any break, no matter how minor, in transmittal of RTM data onshore or in communications between onshore and rig personnel. However, although these concerns were not supported by the proposed regulatory text, they are addressed by the revisions in this final rule to §§ 250.724(b) and 250.724(c). As already discussed, BSEE has revised final § 250.724(b) to require that operators transmit the RTM data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and that operators have the capability to monitor the data onshore, using qualified personnel in accordance with an RTM plan, as provided in final paragraph (c). Finally, onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations.

In addition, as discussed elsewhere in this document, BSEE has revised final § 250.724(c) and removed the language that would have authorized the District Manager to require other measures during a loss of RTM capabilities. These revisions eliminate the language that the commenters perceived could have required shutdowns.

Comments Related to Proposed § 250.724(c)—Concerns About Notifying BSEE

Summary of comments: Various commenters raised concerns about the practicality of the requirement in proposed § 250.724(c) to immediately notify the District Manager if RTM capability is lost. Commenters pointed out that there will be brief losses in monitoring capability from time-to-time, which are expected and unavoidable. However, the operators and the District Managers could be inundated with notifications for very short interruptions that are insignificant and have no potential consequences.

• *Response:* BSEE did not intend the proposed rule to require notifications for every loss of RTM capability, no matter how brief or insignificant the interruption might be. BSEE agrees with the commenters that it would be impractical and an unnecessary burden for operators and the District Managers if immediate notifications were required for every minor interruption. Accordingly, BSEE has removed the proposed requirement to immediately notify the District Manager every time RTM is interrupted from the final rule. However, BSEE still expects to be informed when there is a significant or prolonged loss of RTM capability as outlined in the RTM plan, that potentially could increase the risk of a well-control event. Thus, as described in more detail elsewhere, BSEE has added a provision to the final rule, at § 250.724(c), requiring operators to develop an RTM plan that includes a description of how the operator will notify the District Manager when such a loss occurs.

Comments Related to Proposed § 250.724(c)—Requests To Delete RTM Requirements and/or Require RTM Plans

Summary of comments: Several commenters requested that BSEE delete the proposed RTM requirements from the final rule. Some of those commenters also suggested that, if BSEE did not delete RTM altogether, it should replace at least some of the prescriptive RTM requirements with a performance-based requirement for operators to develop their own RTM plans (similar to the safety and environmental management system—SEMS—plans required by BSEE regulations), which would be available to BSEE upon request. Some other commenters, who did not expressly urge BSEE to require RTM plans, nonetheless relied on the existence of their own RTM plans to justify their recommendation that BSEE eliminate RTM requirements from the final rule. Some of the commenters who suggested that BSEE require RTM plans also suggested specific issues that should be covered in such RTM plans (*e.g.,* qualifications for onshore personnel; protocols for communications between rig and onshore personnel; protocols for handling interruptions in such communications and in RTM capabilities; location of onshore monitoring facilities), although each plan could be tailored to fit the circumstances applicable to each rig operator.

• *Response:* BSEE agrees with many of the commenters' suggestions regarding the potential advantages of a performance-based RTM plan requirement. In particular, BSEE agrees that requiring rig-specific RTM plans could allow operators to optimize their resources to better focus on areas or issues that need the most attention. Further, the availability of the RTM plans to BSEE would provide extra insight into ways in which RTM can be used to improve safety and environmental protection. In addition, such plans would provide operators with a more flexible, performance-based opportunity to address issues such as what to do when RTM capabilities and communications are interrupted.

Accordingly, BSEE revised the final rule, as requested by some commenters, to include a requirement, in final § 250.724(c), that operators develop and implement RTM plans and make the plans available to BSEE upon request. That provision requires that the RTM plans include certain information, such as:

◦ Descriptions of how RTM data will be transmitted onshore, and the onshore location(s) where the data will be monitored and stored;
◦ Procedures for communications between onshore and rig personnel;
◦ Actions to be taken if such communications or RTM capabilities are lost;
◦ Procedures for responding to any significant or prolonged interruptions of monitoring or communications; and
◦ A protocol for notifying BSEE of any significant or prolonged interruptions.

These RTM plan requirements will complement the other RTM requirements in § 250.724(a) and (b).

Comments Related to Proposed § 250.724—Miscellaneous Concerns

Summary of comments: Several comments did not fit into the summaries already discussed. These miscellaneous comments include assertions: (a) That the RTM requirements will not result in increased functionality, reliability and operability of BOPs and that no RTM centers are known to reduce incidents and increase safety; (b) that rig alarms and visual inspection are more effective than RTM; and (c) that the rule requires the gathering of a huge amount of information.

• *Response:* Some of these miscellaneous comments express opinions (*e.g.,* that rig alarms and visual inspection are better than RTM; the RTM requirement will not result in increased functionality, reliability and operability of BOPs), with no supporting facts or explanations and some are largely irrelevant (*i.e.,* this rulemaking does not require operators to establish RTM centers). For the reasons stated in the proposed rule and elsewhere in this document, BSEE expects the use of RTM to improve safety and environmental protection significantly and that such improvements will be seen over time. BSEE understands that the RTM provisions of this final rule will result in more information being gathered, and BSEE took that into account in assessing the potential costs and benefits of this rule under E.O. 12866 and the Paperwork Reduction Act, as discussed in part VIII and in the final RIA. For all of the reasons stated in this document and in the final RIA, BSEE has determined that the benefits of the final RTM requirements, including the value of the RTM information to be collected, are appropriate in relation to the potential costs, including the burdens associated with collecting RTM information.

Blowout Preventer (BOP) System Requirements

What are the general requirements for BOP systems and system components? (§ 250.730)

As provided for in the proposed rule, this section consolidates and revises requirements from several sections of the existing regulations for design, fabrication, installation, maintenance, inspection, repair, testing and use of BOP systems and BOP components. Among other things, paragraph (a) of final § 250.730 requires compliance with relevant provisions of API Standard 53 and several related industry standards and adds a performance-based requirement that the BOP system be able to meet anticipated well conditions and still be able to seal the well. Paragraph (b) requires that operators ensure that design, fabrication, maintenance, and repair of the BOP system is done pursuant to the requirements contained in part 250, OEM recommendations (unless otherwise directed by BSEE), and recognized engineering practices. Paragraph (c) requires operators to use failure reporting procedures consistent with specified industry standards and to report failures to BSEE. Paragraph (d) requires that if an operator uses a BOP stack manufactured after the effective date of this rule, that BOP stack must have been manufactured in accordance with API Spec. Q1. Proposed § 250.730 has been revised in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.730(a)—BOP Design, Installation, and Maintenance

Summary of comments: In response to the language in proposed § 250.730(a) that operators ''must design, install, maintain, inspect and use'' BOP system components, several commenters pointed out that operators do not design, install, or maintain BOP systems. Typically, drilling contractors select and obtain the equipment from OEMs and have the BOP stack built to order in accordance with API Standard 53. These commenters recommended revising this section to replace ''design'' with ''ensure'' or ''select.''

• *Response:* Although the requirements in § 250.730(a) have long been in place under existing regulations (former § 250.440), BSEE agrees with the comment that operators do not usually design, install, or maintain the BOP systems. Therefore, BSEE has revised final § 250.730(a), as suggested by commenters, to state that lessees/operators must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. This change addresses the commenters' concern, while clarifying that the lessee or operator retains overall responsibility for ensuring the BOP system's proper, design, installation, maintenance, inspection, testing and use.

Comments Related to Proposed § 250.730(a)—BOP Design Responsibility

Summary of Comments: Some comments asserted that the requirements in proposed § 250.730(a) would implicitly impose QA/QC and oversight responsibilities for BOP equipment on lessees/operators that are infeasible, given that the design, manufacturing and testing of such equipment are completed before the contracts between the lessees/operators and drilling contractors are in place.

• *Response:* As explained in the previous response, BSEE has revised final § 250.730(a) to require that the operators ''ensure'' that the equipment is designed, installed, maintained, etc., to ensure well control. To the extent that drilling contractors actually perform those activities, the contractors will be jointly and severally responsible for compliance with this provision.

Comments Related to Proposed § 250.730(a)—MASP

Summary of comments: Some commenters recommended that BSEE change the reference to ''MASP'' in proposed § 250.730(a) (*i.e.,* that the working pressure rating of each BOP component exceed the applicable MASP) to ''maximum anticipated wellhead pressure'' (''MAWHP''). They asserted that there is no industry agreed-upon definition of ''MASP,'' but that MAWHP is defined in API Standard 53.

• *Response:* BSEE does not agree that the recommended change is necessary. As a practical matter, for surface BOPs, the MASP is the same as the MAWHP; and for subsea BOPs, the MASP, when taken at the mudline as required by § 250.730(a), is also the same as the MAWHP. BSEE does not agree that use of ''MASP'' will cause any confusion. BSEE's existing regulations (*e.g.,* former § 250.448(b)), have long used the term ''MASP,'' and BSEE does not believe that the industry will have any difficulty in understanding the meaning and use of that term in this rule.

Comments Related to Proposed § 250.730(a)—Annular BOPs

Summary of comments: Several commenters also stressed that annular BOPs capable of meeting the specified pressure rating for ''each BOP component'' under proposed § 250.730(a) are not currently available and are not considered technologically feasible in the near term. They suggested that BSEE clarify that this proposed requirement applies only to lower stack components (including and below the uppermost ram) and that components above the uppermost ram (*e.g.,* annular and LMRP or riser connect) should be excluded. Another commenter suggested excluding annular BOPs that comply with § 250.738(g), which sets procedural requirements for annular BOPs with rated working pressures (RWPs) lower than anticipated surface pressure.

• *Response:* BSEE agrees that annulars may not be able to meet the MASP requirements. BSEE is aware that the current design for annulars does not match the pressure rating for large ram preventers greater than 10,000 psi.

Annulars are typically used with wellbore pressures less than MASP. An annular does not have any locking mechanisms to keep it closed, as do pipe rams and blind shear rams, and it will relax and not seal if the hydraulic pressure is lost. Thus, a single annular is not commonly used for well-control purposes; rather, annulars are commonly used in conjunction with other MASP-rated components, such as pipe rams or blind shear rams, that can seal the well under MASP. Therefore, excluding annulars from the MASP pressure rating requirement will not decrease safety. Accordingly, we have revised final § 250.730(a) to exclude annulars from the requirement that working pressure rating exceed MASP.

Comments Related to Proposed § 250.730(a)—Flowing Conditions

Summary of comments: Various commenters raised issues regarding the requirement in proposed § 250.730(a) that each ram (except casing shears/supershears) must be capable of closing and sealing the wellbore at all times, including under flowing conditions. Some commenters viewed the proposed language as requiring each ram to be assessed against an absolute worst-case event (*i.e.,* any conceivable flowing conditions), and that it is not realistic to expect a drilling BOP ram to close and seal on a high flow-rate well stream. Some comments asserted that the ability to test to such extreme worst-case conditions does not exist. Various comments asserted that the actual goal of the regulation should be for the BOP system as a whole (including both annulars and rams) to reliably shut-in the well under ''reasonably anticipated'' or ''anticipated'' flowing conditions. Multiple commenters emphasized that the industry has demonstrated the capability to successfully seal the wellbore under a variety of anticipated flowing conditions (with flow checks using an annular BOP). Some commenters, however, claimed there are currently no criteria for determining anticipated flowing conditions; while other comments suggested that anticipated flowing conditions should be defined by the OEM.

Multiple commenters, therefore, asked BSEE to clarify the conditions that the equipment must be designed to meet, while other commenters specifically asked BSEE to require that the anticipated flowing conditions be defined in the APD for the specific operation and well conditions.

• *Response:* BSEE recognizes that a single ram may not be capable of closing and sealing the wellbore at all times under all possible flowing conditions. BSEE is also aware that testing an individual ram component under all possible well conditions is not feasible with current testing mechanisms. Accordingly, BSEE has revised final § 250.730(a) to clarify that the BOP system, not each ram, must be capable of closing and sealing the wellbore at all times under ''. . . anticipated flowing conditions for the specific well conditions . . . .'' If an operator has any questions about the anticipated flowing conditions in any specific case, it may request assistance from the District Manager.

Comments Related to Proposed § 250.730(a)—Concerns About Compliance Date

Summary of comments: Commenters also raised concerns that implementation of proposed § 250.730 would be required within 90 days of publication of the final rule. They asserted that BOPs available today are not designed to close and seal under the worst-case flowing conditions that the commenters assumed the rule would require. Similarly, various commenters stated that BSEE has not defined testing parameters and protocols necessary to meet such scenarios. Thus, multiple commenters requested that BSEE significantly extend the proposed 90-day implementation period in order to provide time for manufacturers to develop new BOPs and for drillers to purchase and install such new designs.

• *Response:* In light of the revisions to final § 250.730(a) previously described (*i.e,* the deletion of the requirement for each ram to close and seal, and the insertion of ''anticipated'' before ''flowing conditions''), BSEE is not changing the compliance date for requiring that BOP systems have the capability to close and seal the well. BSEE is aware, and several industry commenters have stated, that industry has already demonstrated that reasonably available existing BOP systems are capable of successfully closing and sealing the wellbore under a variety of flowing conditions under the existing BOP regulations (former § 250.440). Given the changes to the final rule language, and industry commenters' acknowledgment of their ability to comply with the similar requirements under the existing regulations, BSEE does not anticipate that industry will need to make any significant changes to its current or planned BOP systems to comply with the final rule.

Comments Related to Proposed § 250.730(a)(2)—Normative References

Summary of comments: In general, some industry commenters did not support the incorporation by reference of the additional standards associated with API Standard 53, as listed in proposed § 250.730(a)(2), since those listed standards are merely normative references in API Standard 53. These associated documents are manufacturing specifications, and since they are already referenced in API Standard 53, the commenters stated that it is redundant to also reference them in the regulations. Several major industry commenters requested that, if BSEE does reference these documents in the regulations, then it should clarify that only the relevant provisions of those documents are required to be complied with.

• *Response:* BSEE recognizes that the industry standards listed in § 250.730(a)(2) are normative references within API Standard 53. BSEE is including the standards in the regulations, however, because they provide certain relevant specifications for BOP system components, and are important to compliance with API Standard 53 itself. As requested by industry commenters, however, BSEE has revised final § 250.730(a)(2) to clarify that the BOP system must meet those provisions of the listed industry standards that apply to BOP systems.

Comments Related to Proposed § 250.730(a)(2)—Standards—Current Editions

Summary of comments: Other commenters stated that the additional standards listed in proposed § 250.730(a)(2) are outdated equipment manufacturing standards, and that incorporating a specific outdated edition renders equipment manufactured prior to the standard, or manufactured to earlier versions of the standard, obsolete. They asserted that incorporating only API Standard 53, which includes updated normative references, and deleting the outdated standards listed in paragraph (a)(2), would resolve this issue. Alternatively, some commenters suggested that the regulation should allow equipment to be used if it complies with the editions of API Standard 53 and the associated standards that were in effect at the time the equipment was manufactured.

A commenter also noted that there are significant misalignments between API Standard 53 and the current versions of most of these associated standards (*e.g.,* accumulator capacity requirements), which would make it impossible to comply with API Standard 53 and these associated standards. The commenter also noted that API Standard 53 and these associated standards are currently being revised, and that the API committees working on the new editions are aware of these misalignment issues.

• *Response:* Whenever BSEE incorporates a standard by reference in the regulations, it must incorporate a specific edition of the standard (*see* 1 CFR part 51), and compliance is then required with the incorporated standard. BSEE proposed to incorporate the most recent (Fourth) edition of API Standard 53, which refers to the other standards but which—in contrast to Federal regulations—does not specify the edition of those other standards to which it refers. Some of the associated standards incorporated by reference in § 250.730(a)(2) are the current versions (*e.g.,* API Spec. 16A and API Spec. 16D); other standards have been updated and new editions adopted by industry since BSEE developed and issued the proposed rule. BSEE understands the industry is also working to update some of the current standards. BSEE will evaluate any new editions of the standards as they are finalized by industry. If BSEE determines that any such revised standards are appropriate for incorporation in this regulation, BSEE may do so in a separate rulemaking. In addition, as previously discussed, an operator that wishes to use equipment manufactured to a more recent edition of the incorporated standard, may ask for approval to do so in accordance with § 250.198(c) and § 250.141 or § 250.142.

Comments Related to Proposed § 250.730(a)(3)—Pipe and Variable Bore Rams (VBRs)

Summary of comments: Commenters raised concerns that the proposed requirement in § 250.730(a)(3) (*i.e.,* that pipe rams and VBRs be able to close and seal any drill pipe, workstring and tubing) is not achievable for tubing with control lines, electric cable, and flat packs. Commenters asserted that the interstices between the tubular and these ancillary lines become leak paths when the pipe or VBRs are closed around the tubing arrangement. In addition, some commenters stated that the proposed requirement would be redundant with existing dual barrier systems (including annulars), and thus would provide negligible additional improvements to safe operations. Commenters recommended that tubing with such exterior lines be excluded from the proposed requirement. If the requested exclusion from the proposed requirement is not adopted, some commenters suggested that BSEE revise the rule to allow alternative control measures based on risk assessments.

• *Response:* BSEE agrees with the comments about pipe rams and VBRs not being able to close and seal around tubing with exterior control lines and flat packs. An annular is the only BOP component currently able to seal around tubing with exterior control lines and is only used for a low pressure situation, which is usually the case when running tubing with exterior control lines. Accordingly, BSEE has revised final § 250.730(a)(3) to clarify that pipe rams and VBRs are not required to be able to close and seal around tubing with exterior control lines and flat packs. In addition, BSEE has determined that this exclusion will not have significant safety or environmental consequences since §§ 250.733(a) and 250.734(a)(1)(ii) will require that the shear rams be able to cut and seal tubing with exterior control lines in the hole.

Comments Related to Proposed § 250.730(a)(3)—Claimed Conflicts With API Standard 53

Summary of comments: Commenters requested clarification regarding the requirement in proposed § 250.730(a)(3) that the pipe rams and VBRs be able to close and seal the tubing using the ''proposed regulator settings'' of the BOP system. The commenters claimed that this language potentially conflicts with API Standard 53. The commenters also suggested that the reference to ''regulator settings'' should be removed from this provision because such settings are part of the BOP control system described in § 250.730(a).

• *Response:* This regulation does not prescribe any specific requirements for regulator settings. BSEE requires only that the regulator settings function as designed or as specified in the APD submitted to and approved by BSEE. Therefore, BSEE does not believe that this provision will cause any conflict or confusion for operators, including with respect to API Standard 53, and thus no change or further clarification is necessary.

Comments Related to Proposed § 250.730(a)(4)—Approval of BOP Changes

Summary of comments: With regard to proposed § 250.730(a)(4), requiring that operations be suspended pending BSEE approval of any changes to the BOP or control systems that would alter previously approved schematic drawings—some commenters observed that any changes to the BOP stack or control system would be made between wells. Thus, any changes to the drawings and equipment would be included in the APD for the next well. Those commenters recommended deleting that portion of § 250.730(a)(4) that would require such suspensions.

• *Response:* BSEE disagrees with the comment's suggestion that changes would always be made between wells. BSEE understands that this is usually the case; however, there are circumstances where repairs and modifications to the BOP or control system are made at other times and not necessarily between wells. Thus, there is no reason to revise this provision.

Comments Related to Proposed § 250.730(a)(4)—Schematic Drawings

Summary of comments: A commenter recommended that BSEE clarify § 250.730(a)(4) to specify that the schematic drawings required for the BOP and its control system be the same drawings listed in § 250.731(b)(1) through (10).

• *Response:* No changes to the proposed paragraph (a)(4) are necessary. Under final § 250.730(a)(4), schematic drawings may include other schematics (such as those required under § 250.737(d)(12)) that are not listed in § 250.731(b)(1) through (10).

Comments Related to Proposed § 250.730(b)—Lowest Level Practicable

Summary of comments: A commenter recommended that BSEE revise the first sentence in proposed § 250.730(b) to require that the design, fabrication, maintenance, and repair of BOP systems reduce risks to the lowest level practicable instead of ''according to the requirements of this subpart, OEM recommendations, . . . and recognized engineering practices'' as proposed by BSEE.

• *Response:* The requested changes are not necessary. BSEE expects these types of activities to utilize recognized engineering practices that reduce risks to the lowest level practicable, as already required by existing § 250.107(a)(3).

Comments Related to Proposed § 250.730(b)—BOP Design and Fabrication

Summary of comments: Other comments stated that operators do not design and fabricate the BOP systems; they select the equipment based upon their specifications and capabilities. Accordingly, commenters suggested that BSEE should revise the text, replacing ''design, fabricate, maintain, and repair'' with ''select, maintain, and repair.''

• *Response:* BSEE agrees with the comments that operators do not usually design and fabricate the BOP systems. Therefore, BSEE revised this paragraph in the final rule to state that an operator must ensure that the design, fabrication, maintenance, and repair of its BOP system is in accordance with the requirements contained in the part. This change will help clarify that the lessee or operator is responsible for ensuring the BOP system's proper, design, installation, maintenance, inspection, testing and use even if it does not design and fabricate the BOP system.

Comments Related to Proposed § 250.730(b)—BOP Repair and Maintenance

Summary of comments: A commenter suggested that repair and maintenance should be carried out in accordance with OEM specifications and maintenance manuals and the equipment owner's planned maintenance procedures. Additionally, a commenter advised that the OEM's recommendations for repair and maintenance should include the quantity and quality of parts that the owner or operator subsequently uses.

• *Response:* The suggested changes are unnecessary. As previously discussed, the lessee or operator is responsible for ensuring that the BOP system is designed, repaired and maintained in accordance with the requirements of this final rule, which includes ensuring that the BOP equipment is suitable for the conditions under which it will be used (*see, e.g.,* § 250.731), as well as with any OEM recommendations, which would include OEM specifications and maintenance.

As to the second comment, BSEE expects the equipment to operate as designed and to be used under the conditions for which it was designed. However, the commenter's suggestion that OEMs should include the quantity and quality of parts subsequently used by the operator in the OEMs' recommendations for repair and maintenance is beyond the scope of this rulemaking, which addresses requirements that must be met by operators.

Comments Related to Proposed § 250.730(b)—Recognized Engineering Practices

Summary of comments: Commenters recommended that the phrase ''recognized engineering practices'' be removed since the phrase is vague and undefined.

• *Response:* The recommended deletion is neither necessary nor appropriate. Recognized engineering practices are commonly understood to be found in established codes, industry standards, published peer-reviewed technical reports or industry RPs, and similar documents applicable to engineering, design, fabrication, installation, operation, inspection, repair, and maintenance activities.

Comments Related to Proposed § 250.730(b)—Training of Personnel

Summary of comments: Commenters recommended that BSEE remove the proposed requirements for training of repair and maintenance personnel. Some commenters observed that OEMs do not publish training, qualification, and maintenance recommendations. Others stated that OEM maintenance recommendations are one 'size fits all', since OEMs do not have a clear understanding of how the equipment will be used, maintained or preserved. Commenters emphasized that the equipment owners are responsible for the condition of the equipment and that they should be responsible for defining the skills and training for their maintenance personnel. They also noted that operators are already required to address training as part of their SEMS program under BSEE's SEMS regulations (*see* § 250.1915), and that the equipment owners (*e.g.,* rig contractors) are also establishing training standards for their personnel. One commenter recommended that BSEE should implement an accredited/licensed training program, to be developed by the industry, instead of relying solely on OEMs and recognized engineering practices.

• *Response:* None of the suggested changes are necessary. BSEE agrees that the SEMS training requirements are pertinent to personnel maintaining, inspecting or repairing BOPs, and BSEE added an express reference to those requirements in final § 250.739(d), as discussed elsewhere in this document. However, BSEE does not see any inconsistency between the requirements in § 250.730(b), for training based on OEM recommendations and recognized engineering practices, and BOP-related training as part of the SEMS program and under § 250.739(d). There is no reason why operators' SEMS training programs should not incorporate OEM recommendations and other recognized practices.

In addition, BSEE does not agree that it should require a new training program, whether developed by industry, as suggested by the commenter, or not. Contrary to the commenter's assumption, BSEE is not relying solely on OEM recommendations and recognized engineering practices. As explained previously, the SEMS training requirements apply to BOP-related training, and those requirements should be sufficient without BSEE creating yet another training program.

Comments Related to Proposed § 250.730(b)—Meaning of OEM

Summary of comments: Some comments questioned the meaning of OEM in this provision. They asked if the OEM is the BOP component manufacturer or the suppliers of parts used by the component manufacturer. Commenters suggested that, if the proposed rule implies that service and maintenance personnel must receive training from subcontractors of the OEM, it would not be a workable rule. One commenter suggested that there would be a severe impact on the availability of personnel permitted to carry out maintenance, depending on the definition of OEM.

• *Response:* BSEE does not agree that any definition of OEM is necessary at this time. BSEE expects that where operators have relevant recommendations from manufacturers of individual parts of the BOP system, as well as recommendations from the BOP component manufacturer, they are able to implement both sets of recommendations. Conversely, this regulation does not require operators to follow the recommendations of OEMs, whether manufacturers of BOP components or individual pieces of equipment, if no such recommendations exist. In the event an operator has any questions as to the applicability of any specific OEM recommendation, it may ask the District Manager for assistance.

Comments Related to § 250.730(c)—BOP Failure Reporting Procedures

Summary of comments: A commenter recommended that BSEE add near-miss reporting to failure reporting requirements. Commenters also suggested that BSEE define ''failure'' and specify the types of failure covered by this provision.

• *Response:* The comment regarding near-miss reporting is outside the scope of this rulemaking and the suggested changes are not necessary or appropriate at this time.[15]

BSEE agrees, however, with the suggestion that a definition of ''failure'' would clarify the scope and applicability of this provision. Since there are no definitions of ''failure'' in any of the industry standards (*i.e.,* API Spec. 6A, API Spec. 16A, or API

[15] BSEE notes, however, that the U.S. Bureau of Transportation Statistics has developed (with BSEE's assistance) a voluntary near-miss reporting system for OCS facilities and operations. More information is available at *www.SafeOCS.gov.*

Standard 53) referenced in this provision, BSEE added a general definition of ''failure'' in final § 250.730(c)(1).

Comments Related to Proposed § 250.730(c)—Failure Reporting Under API Standard 53

Summary of comments: A commenter asserted that since API Standard 53 covers failure reporting by the owner of the equipment, regulations on this point are not necessary. Since it is covered in API Standard 53, the commenter presumed that a prudent drilling contractor would conduct such follow-up.

• *Response:* BSEE understands that failure reporting requirements are found throughout various voluntary industry standards, several of which are incorporated in this provision. As with any voluntary standard incorporated into BSEE's rules, that incorporation has the intended benefit of making compliance with the standard a regulatory requirement, which promotes consistency across the regulated community. BSEE is also including additional failure reporting requirements in this rule. Such reporting can lead to improved and more reliable equipment.

Comments Related to Proposed § 250.730(c)—Manufacturing Standards

Summary of comments: Some commenters suggested that BSEE only needs to reference API Standard 53 in this section, and that BSEE should remove the references to API Spec. 6A and Spec. 16A. API Standard 53 is an operational document, while API Spec. 6A and API Spec. 16A are manufacturing-related failure reporting methods. Alternatively, BSEE needs to provide guidelines on the intended use for referencing Spec. 6A and Spec. 16A.

• *Response:* No changes to this proposed paragraph related to this comment are necessary. BSEE incorporated the failure reporting requirements from all three of the industry standards in the proposed provision because each standard contains useful reporting procedures that the others do not. In addition, the incorporation of the failure reporting procedures of API Spec. 6A and API Spec. 16C adds value to this provision because those standards apply specifically to equipment that is part of a BOP system. BSEE expects that the failure reporting procedures of all three standards will complement each other. On the other hand, BSEE sees no need to provide guidance on the potential use of API Specs. 6A and 16A at this time. As experience and additional information are gained under this rule, BSEE will both provide guidance and clarification on this rule as necessary, and consider any new information it learns in considering whether any adjustments to the rule may be warranted.

Comments Related to Proposed § 250.730(c)—Failure Database

Summary of comments: Some commenters advised BSEE that a group of drilling contractors have developed a database for reporting BOP failures. These failures are automatically copied to the OEM by the database. According to the commenters, this group plans to implement the failure reporting database industrywide. Within a year or so, according to the commenter, this group may have sufficient data to identify problem areas, to collectively focus on these areas until design and procedure changes are implemented that will make well-control equipment even more reliable.

• *Response:* The commenters recommended no specific changes to the rule or other action by BSEE. In any case, it would not be appropriate for BSEE to take any action now based on a program that may or may not exist in the future. However, BSEE encourages continued proactive evaluation by industry of potential failure mechanisms to enhance safety and environmental protection offshore.

Comments Related to Proposed § 250.730(c)—Written Failure Report

Summary of comments: With regard to proposed § 250.730(c)(1), a commenter suggested replacing the requirement for a ''written report'' of equipment failure to the manufacturer with ''written notification.''

• *Response:* BSEE agrees that such a change is appropriate. This requirement is only the first step in the failure reporting process, and a notice at this step is sufficient. A more detailed analysis report of the failure will be provided to the manufacturer, as well as to BSEE, under final § 250.730(c)(2). Accordingly, BSEE has revised final § 250.730(c)(1) to require only a written notice.

Comments Related to Proposed § 250.730(c)—Concerns About Who Should Submit Failure Reports

Summary of comments: Some commenters stated that, since operators do not own the BOP equipment, and are not the primary source of failure data, failure reports should come from the drilling contractors. Therefore, the commenters recommended revising this section to state that the operator must ''ensure'' that a failure report is provided to the manufacturer.

• *Response:* BSEE does not agree that these suggested changes are necessary. In paragraph (c), BSEE is requiring the operator to provide the notifications and handle the interactions with the manufacturer because operators are responsible for all activities under a lease.

Comments Related to Proposed § 250.730(c)—Failure Investigation and Analysis

Summary of comments: A commenter noted that not every failure warrants a full investigation and suggested replacing ''investigation and a failure analysis'' in the proposed rule with ''investigation and, when required, a failure analysis.'' According to the commenter, major failures should be discussed with the OEM and an investigation initiated; however, the system would be unsustainable if every (including a minor) failure required investigation by the OEM, a third-party or a combination of both.

• *Response:* BSEE disagrees with the assertion that the failure reporting system would break down if every minor failure required investigation. It is possible that even a so-called ''minor'' failure could indicate a potentially more serious problem that warrants correction, which would otherwise escape attention, if not for the investigation of the ''minor'' failure. Since it is not possible to know in advance which seemingly minor failures may lead to a ''major'' problem, BSEE does not believe that it is appropriate to limit the requirement as suggested.

Comments Related to Proposed § 250.730(c)—Timing of Failure Analysis

Summary of comments: A commenter also suggested that a 60-day window to complete and submit failure analysis findings is not realistic. It often takes 6 months or more for these findings to be obtained and approved. Reporting of the analysis results within 60 days will potentially lead to narrowing the scope or lessening the intensity of the investigation and diminishing its potential value.

• *Response:* The commenter apparently misinterpreted the proposed rule as requiring that the findings of the failure analysis be produced within 60 days, when the proposed requirement actually provided that the investigation and analysis must be initiated within 60 days. Nonetheless, BSEE agrees with the commenter that 60 days may not be sufficient for an effective failure analysis to be performed. However, BSEE does not agree with the commenter's suggestion that 6 months or more may be necessary to produce the findings of such analysis. There is value to concluding the analysis, and providing the results to the manufacturer at a reasonably early date after the failure, so that any necessary follow up actions can be taken sooner, and thus potentially prevent additional related failures from occurring. Accordingly, BSEE has revised final § 250.730(c)(2) by modifying the time for performing a failure analysis to 120 days.

Comments Related to Proposed § 250.730(c)—Failure Occurrence

Summary of comments: A commenter suggested that BSEE revise this section to reflect only failures that occur when the BOP system is in service and not during maintenance periods.

• *Response:* BSEE does not agree that these suggested changes are necessary. In § 250.730(c), BSEE incorporated the failure reporting requirements of 3 industry standards, and those standards provide enough specificity as to when a failure triggers the need for reporting. In any event, a failure may be an indicator of a serious problem requiring investigation and potential follow-up action whenever the failure occurs.

Comments Related to Proposed § 250.730(c)(2)—Analysis Report

Summary of comments: Another commenter recommended that BSEE revise proposed paragraph (c)(2) by changing ''copy of the analysis'' to ''results of the investigation.''

• *Response:* BSEE agrees with the substance of this comment and has revised final § 250.730(c)(2) by changing ''copy of the analysis'' to ''copy of the analysis report.'' This revision will ensure that the results of the analysis, including any recommendations for corrective action, are documented and provided to the manufacturer. BSEE expects that the analysis report will describe the analysis as well as the results, since it is frequently useful to review the analysis to determine the adequacy of the results. For the same reason, BSEE has revised final § 250.730(c)(2) to require that a copy of the analysis report also be provided to BSEE, since it is important that BSEE be aware of the results of failure analyses in order to help BSEE identify potential trends and, if appropriate, make others aware of a potential problem that may require action to prevent similar failures or to improve equipment reliability.

Comments Related to Proposed § 250.730(c)(3)—Questions Concerning Who Must Notify BSEE of Failures

Summary of comments: A commenter requested that BSEE clarify paragraph (c)(3) regarding who is required to notify BSEE of an equipment design change or change in operating or repair procedures; *i.e.,* whether it should be the operator or the contractor (the owner of the equipment involved in the failure.)

• *Response:* Paragraph (c)(3) clearly requires the operator to report the design changes or modified procedures, unless another person covered by the regulatory definition of ''you'' informs the operator it has done so.

Comments Related to Proposed § 250.730(c)(3)—Submittal of Failure Report to BSEE

Summary of comments: Some comments questioned why the report of equipment changes or procedural changes must be sent to BSEE's headquarters office instead of the District Manager.

• *Response:* BSEE will require that these reports be sent to BSEE headquarters in order to ensure that emerging trends occurring across various Districts and Regions are recognized early and that potentially serious concerns can be addressed in a coordinated and uniform way nationwide.

Comments Related to Proposed § 250.730(d)—Scope of API Spec. Q1 (Quality Control)

Summary of comments: One commenter asserted that the proposed regulation at § 250.730(d) does not clearly define the scope of the requirement to implement API Spec. Q1. The commenter requested that BSEE clarify whether this requirement only applies to complete BOP stacks, or if it also includes any BOP component that is manufactured after the implementation of the rule (*e.g.,* a single BOP ram).

• *Response:* The intent of the provision is that the complete BOP stack must be manufactured pursuant to API Spec. Q1, not the individual components of the BOP system.

Comments Related to Proposed § 250.730(d)—Reference to ISO 17011

Summary of comments: Some commenters suggested that the reference to ISO 17011 is incorrect and that the actual reference should be to ISO 17021. In addition, they suggested that BSEE add ISO 29001 as an optional alternative standard. They also noted that ANSI/API Spec. Q1 8th edition is no longer available from ANSI, and that BSEE should incorporate API Spec. Q1 9th edition, as it is the correct edition. In addition, other commenters asserted that there is no API standard for a BOP stack, and that API Spec. Q1 would apply only to the individual components.

• *Response:* BSEE already incorporates ISO 17011 under §§ 250.1900, 250.1903, 250.1904, and 250.1922 for qualifications of accreditation bodies under SEMS. Incorporating that standard here ensures consistency with the SEMS requirements for quality management systems. Regarding incorporation of ISO 29001 as an optional alternative standard, BSEE generally expects that operators are following the industry developed standards, regardless of whether the standard is incorporated in the regulations. However, when BSEE incorporates a standard in the regulations, compliance with that standard is not optional. An operator may request approval from BSEE to comply with an alternative standard under § 250.141. BSEE recognizes the concerns related to incorporating the most current edition of each standard. The issue of incorporation of a newer edition was addressed in comment-responses under § 250.198. The change to a new edition or removal of a discontinued standard is not automatic and requires rulemaking. Operators may request approval from BSEE to follow a later edition of a standard under § 250.198(a)(1). BSEE recognizes that API Spec. Q1 applies to the manufacture of individual components, however, as previously stated, the intent of the provision is that the complete BOP stack must be manufactured pursuant to API Spec. Q1, not the individual components of the BOP system.

Comments Related to Proposed § 250.730(d)—Applicability of API Spec. Q1 (Quality Control)

Summary of comments: Some comments requested that BSEE clarify this provision since ''BOP stacks'' are not ''manufactured;'' *i.e.*, only the components are manufactured. In addition, compliance with the API standard incorporated by reference should be sufficient; there is no need for BSEE to add ISO requirements.

• *Response:* BSEE recognizes that API Spec. Q1 applies to the manufacture of individual components, however, as previously stated, the intent of the provision is that the complete BOP stack must be manufactured pursuant to API Spec. Q1, not the individual components of the BOP system. The incorporation of ISO 17011 ensures the manufacturers of the BOP systems follow the quality management system required by API Spec. Q1.

Comments Related to Proposed § 250.730(d)(1)—Approval of Other Quality Programs

Summary of comments: With regard to the proposed option under § 250.730(d)(1) for seeking BSEE approval for BOP equipment manufactured under some quality program other than API Spec. Q1, a commenter stated that operators are not typically in the business of manufacturing BOPs for their operations. Instead, they typically select a MODU/Rig with a BOP as part of the equipment package. Therefore, these requirements should be placed upon the drilling contractor when applying for their license to operate in the U.S.

Another commenter asserted that proposed § 250.730(d)(1) would allow for potential approval of an alternative quality program (instead of API Spec. Q1) for the manufacture of BOP equipment, but that the path for obtaining such approval does not appear to be available to contractors (unless sponsored by an operator).

• *Response:* Section 250.730(d) is applicable to operators/lessees in the same way that most of the requirements in existing part 250 are applicable. Ultimately, the operator/lessee is responsible for compliance with these requirements. As is common practice under the regulations, however, operators may contract with others for the performance of many of the required actions. In that case, the operator/lessee and the person (contractor) actually performing that activity are jointly and severally responsible for compliance with the applicable requirement. (*See* § 250.146(c).) The actions required by § 250.730(d) are no different.

Comments Related to Proposed § 250.730(d)(1)—Request for Alternative Quality Programs

Summary of comments: Commenters also noted the proposed rule refers to approval of alternatives under § 250.141, which is granted by District Managers and Regional Supervisors, but requires that the request be submitted to the Chief, Office of Offshore Regulatory Programs (OORP). The commenter noted that, even if approval by the Chief of OORP is obtained, the accepted alternative would not appear to be binding on other District Managers or Regional Supervisors.

• *Response:* BSEE agrees with the comment and revised final § 250.730(d) to require operators to send the requests to use an alternative quality assurance program to the Chief of OORP and not to submit the request under § 250.141.

What information must I submit for BOP systems and system components? (§ 250.731)

As provided for in the proposed rule, this section consolidates and revises requirements from various former sections for including BOP information in APDs, APMs or other submittals to BSEE. Among other things, paragraphs (a) and (b) require submission of a complete description and schematic drawings of the BOP system. Paragraph (c) requires submission of a certification by a BAVO: That test data demonstrates the BOP shear ram(s) will shear the drill pipe as required; that the BOP was designed, tested, and maintained to perform under the anticipated maximum environmental and operational conditions; and that the accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system. Paragraph (d) requires additional certification by a BAVO regarding the design and functionality of BOPs used in certain circumstances (*e.g.,* subsea BOPs); while paragraph (e) requires descriptions of the autoshear, deadman, and EDS systems on subsea BOPs. Paragraph (f) requires a certification that the required MIA Report has been submitted within the preceding 12 months. BSEE has revised proposed paragraphs (c) and (d) of this section in the final rule as discussed in the comment responses for this section.[16]

Comments Related to Proposed § 250.731—Concerns About Prescriptive Requirements

Summary of comments: BSEE received a comment stating that this section is overly prescriptive on certain issues, including accumulator sizing, testing, BOP configurations, and QA/QC oversight.

Another commenter claimed that this section would be unnecessary given that effective verification processes are already in place, and that the additional verifications required by this rule would not increase the safety of operations or the reliability of equipment.

• *Response:* BSEE disagrees with the comment that this section is overly prescriptive. The specific information required to be submitted with APDs, APMs and other submissions is necessary to help BSEE make informed decisions in the approval process by providing a clear understanding of the BOP system, equipment and operations. These provisions essentially set performance-based goals for the operators and verifiers, and several of the descriptions of processes and equipment that must be verified are broad enough to allow the persons doing the verification some flexibility to decide whether, under the specific circumstances, it is the equipment or process that should be verified.

BSEE also disagrees with the comment indicating that these verification requirements are unnecessary. BSEE believes that these certification and verification provisions will serve as a useful tool for BSEE and the industry to better ensure—as compared to the current rules and industry practices—that equipment and processes function as intended to protect safety and the environment.

Comments Related to Proposed § 250.731(a)—BOP System Connections

Summary of comments: A commenter noted that § 250.731(a)—requiring descriptions of BOP systems—does not address how the devices along the BOP stack are connected, and that there is no mention of capping or containment points along the BOP stack. The commenter suggests that the BOP system description should address technology that enables better containment and is integrated with that system. Locations along those devices at which containment and capture equipment may be attached should also be included in the system description.

• *Response:* BSEE disagrees with the commenter that capping or containment points should be included in this provision. It is unclear from the comment what devices, technology, and shortcomings the commenter would propose including in § 250.731(a). In any case, source control and containment requirements are adequately covered under final § 250.462, as described elsewhere in this document.

Comments Related to Proposed § 250.731(a)(7) Through (9)—Calculations

Summary of comments: Another commenter observed that the calculations required in paragraphs § 250.731(a)(7) through (9) should demonstrate that there is adequate pressure available to operate each item, especially shear rams. The commenter suggested adding information to the rule

[16] Any information submitted to BSEE should identify any confidential commercial or proprietary information. Any confidential or proprietary information will be protected consistent with the Freedom of Information Act (5 U.S.C. 552) and DOI's implementing regulations (43 CFR part 2); section 26 of OCSLA (43 U.S.C. 1352); 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection;* and 30 CFR part 252, *OCS Oil and Gas Information Program.*

that confirms this is the purpose for conducting the calculations, and suggests that the calculations should take into account the actual planned sequence of BOP operation for deadman, autoshear, and any emergency disconnect programmed operations.

• *Response:* BSEE disagrees with the suggestion that we include the purpose for conducting the calculations, and specifying that the calculations must take into account the planned sequence. BSEE will review the volume and pre-charge accumulator calculations required by paragraphs § 250.731(a)(7) and (9), regardless of sequence, to determine that they are adequate to operate all of the required BOP functions specified in §§ 250.734(a)(3) and 250.735(a) without assistance from the charging system.

Comments Related to Proposed § 250.731(c)—Verification of Shearing Test Data

Summary of comments: Commenters questioned the requirement in proposed paragraph § 250.731(c)(1) for verification of test data on shearing capabilities. Since a test facility to simulate subsea conditions for shear testing does not exist, the requirement for shear testing at water depth implies the BOP is in an environment that simulates the required water depth (instead of on the surface, where shear tests are currently performed). The commenters asserted that there is a risk of damaging equipment when carrying out shearing tests under these conditions. The current industry practice is to apply proven calculation methods to surface shear test data and relevant maximum allowable working pressure conditions. The commenters claimed that if shear tests must be performed under subsea conditions, all of the past shear test data will be irrelevant, and that the time and effort to re-test will likely shut down the GOM for a considerable time. The commenters requested that BSEE revise this requirement to allow supporting engineering calculations instead of test data for shear capability.

Another commenter recommended that the equipment manufacturers should demonstrate shearing capability and provide shearing data instead of operators having to do so.

• *Response:* BSEE agrees that there are technological limitations with testing facilities to simulate subsea conditions. BSEE currently allows, and will continue to allow, operators to use calculations to help verify shearing at water depth. In fact, this provision expressly references final § 250.732, which clearly provides that calculations are used in conjunction with testing to demonstrate that the pipe can be sheared at the well. Therefore, no revision to paragraph § 250.731(c)(1) is warranted.

Comments Related to Proposed § 250.731(c)(2)—Most Extreme Anticipated Conditions

Summary of comments: Most of the comments concerning paragraph § 250.731(c)(2) were related to the requirement for verification that the BOP has been designed, tested and maintained to perform under the ''most extreme anticipated conditions.'' Commenters expressed concerns that the term is undefined and asked whether this phrase refers, for example, to the worst-case discharge or a kick. Commenters also stated that shearing and sealing on flowing wells at worst-case discharge rates is not a typical drilling BOP testing scenario, and the commenters described how testing to verify BOP capabilities is commonly performed. Commenters also pointed out potential hazards from testing for worst-case discharges. Commenters suggested that BSEE's emphasis should be on early detection and correct shut in procedures. A commenter asserted that none of the BOPs currently in use would meet the ''most extreme anticipated conditions'' requirement, and that OEMs do not qualify BOP components under flowing conditions. Commenters recommended that the requirement should be to ''ensure the BOP is designed, tested, and maintained to perform under the anticipated conditions of the well.''

• *Response:* As previously discussed, BSEE has revised paragraph § 250.731(c)(2) by replacing ''to perform at the most extreme anticipated conditions'' with ''to perform under the maximum conditions anticipated to occur at the well.'' This change clarifies this requirement by relying on reasonably predictable, site-specific conditions instead of hypothetical worst-case conditions. In any event, if an operator has any questions about the maximum anticipated conditions in any specific case, it may request assistance from the District Manager.

Comments Related to Proposed § 250.731(c)(3)—Accumulator Systems

Summary of comments: The primary concern raised by commenters regarding paragraph § 250.731(c)(3) was that there appeared to a conflict between the requirement for the accumulator systems, on the one hand, and API Standard 53, as well as the current work industry is undertaking to update the specifications, on the other. Commenters were also concerned that this requirement may impact compliance with API Specs. 16A and 16D. Commenters suggested that BSEE revise this section to require the accumulator system to have sufficient fluid, as defined by § 250.734(a)(3) for subsea accumulators and § 250.735(a) for surface accumulators, to function the BOP system without assistance from the charging system. Other commenters suggested that BSEE revise this provision to refer to the accumulator volume test in API Standard 53.

• *Response:* BSEE does not agree that the suggested changes to paragraph § 250.731(c)(3) are necessary given that, as discussed elsewhere, BSEE has revised the final accumulator requirements of § 250.734(a)(3) for subsea accumulators and § 250.735(a) for surface accumulators to more closely align with API Standard 53. Those revisions are consistent with recommendations made by some of these commenters.

Comments Related to Proposed § 250.731(d)(1)—Verification of BOP Design

Summary of comments: Several of the comments on proposed paragraph § 250.731(d)(1) raised concerns with the requirement for verification that the BOP stack is designed for the specific equipment on the rig and for the specific well design. Commenters asserted that the BOP stacks are not designed for specific equipment; they are selected in consideration of such equipment, which is designed to meet the RWP conditions for the site. Also, BOP stacks are not moved from rig to rig, they are part of the rig equipment and selected to suit the rig design and capabilities. Commenters suggested that BSEE revise this provision to require the BOP stack be suitable for use with the specific equipment on the rig, instead of designed for the equipment.

• *Response:* BSEE does not agree that it is appropriate to remove the reference to ''designing'' the BOP stack. The commenters appear to be interpreting that term unnecessarily restrictively. BSEE believes that the process described by the commenters for how BOP stacks are put together with regard to the equipment on the rig is effectively what BSEE intended by ''designed.'' BSEE does agree, however, with the commenters that the BOP stack must be suitable for use with the specific equipment on the rig. Accordingly, BSEE has revised final § 250.731(d)(1) by inserting ''and suitable'' after the word ''designed.''

Comments Related to Proposed § 250.731(d)—Independent Verification

Summary of comments: A commenter recommended that BSEE revise proposed § 250.731(d) in order to require independent verification of all OCS operations requiring a BOP (rather than just the operations specified in the proposed rule), since the purposes of independent verification are not unique to subsea BOPs, surface BOPs on a floating facility, or BOPs operating in a HPHT environment. The commenter recommended that BSEE revise the rule in this way and then reconsider, after several years, whether the program is working effectively and delivering results, or whether it should be scaled back.

• *Response:* BSEE does not agree that the requested change is appropriate at this time. The verifications required in paragraphs § 250.731(a) through (c) are already applicable to all BOPs. Paragraphs § 250.731(d) through (f) only apply to BOPs used in certain situations because BSEE determined that those situations present higher risks than the other situations in which BOPs are used. The certification and/or verification requirements in paragraphs § 250.731(d) through (f) are specific to the equipment, systems or procedures that are related to such risks. BSEE does not believe those same concerns apply equally to the BOP situations described in paragraphs§ 250.731(a) through (c).

Comments Related to Proposed § 250.731(e)—Subsea BOP Descriptions

Summary of comments: Regarding the proposed requirement in paragraph § 250.731(e) that subsea BOP descriptions include a description of the EDS, commenters recommended that BSEE add ''if installed'' after ''EDS systems.''

• *Response:* BSEE does not agree that this change is appropriate. BSEE already recognizes that an EDS system is not installed or necessary on every rig with a subsea BOP, and § 250.731(e) is not intended to require descriptions for EDS systems that are not present and not otherwise required by the regulations (*see* § 250.734(a)(6)).

Comments Related to Proposed § 250.731(f)—MIA Report

Summary of comments: A commenter suggested that the MIA report certification required by § 250.731(f) is equivalent to the certification in the APD. The commenter suggested that the regulation be revised to consider either an MIA or an APD certification submitted within the past 12 months as sufficient. The commenter also asserted that the regulation does not identify who issues the certification.

• *Response:* This comment is vague and unclear. The MIA certification required in paragraph (f) must be included in the applicable APD or APM, but BSEE is not aware of any duplication between this requirement and any other certification requirement. BSEE does not specify who must provide the certification in paragraph § 250.731(f); so any appropriate person acting on behalf of the operator/lessee may do so.

Summary of comments: Many commenters recommended that BSEE revise or delete § 250.731(f) as duplicative or unnecessary and burdensome. Some commenters requested that BSEE clarify whether this certification is required only if an APD has not been submitted in the previous 12 months. Commenters suggest that, if it is in addition to an APD submitted within the prior 12 months, it appears to be an unnecessary time and expense burden.

Other commenters stated that this report is unnecessary, asserting that all of the requested information is already reported in the APD/APM and the BOP and Well Compatibility Certificate.

• *Response:* BSEE does not agree that paragraph § 250.731(f) should be deleted or revised for any of the reasons suggested by the commenters. As required by § 250.731, a certification statement as described in paragraph (f) must be included each time an APD or APM is submitted. Therefore, if multiple APDs/APMs are submitted within a 12 month period, each one must include a certification statement that an MIA Report was completed within the 12 months preceding that APD/APM. However, the regulation does not require that a certification be submitted every 12 months separately from an APD/APM. Nor does it require that an MIA Report be completed or submitted every time an APD or APM is submitted.

In addition, BSEE disagrees that the requested information (*i.e.*, a certification statement regarding completion of an MIA Report) is already required to be submitted with an APD. Section 250.731(f) itself establishes that requirement. BSEE is unaware of any BOP and Well Compatibility certificate, as mentioned by the commenter, that is currently applicable and duplicative of § 250.731(f).

Comments Related to Proposed § 250.731(c) and (d)—BAVOs

Summary of comments: Several commenters highlighted the fact that BAVOs do not currently exist and that BAVOs cannot be ''approved'' by BSEE until after the effective date of the final rule (*i.e.,* 3 months after publication); therefore, compliance with the proposed § 250.731(c) and (d) certification requirements within 3 months, as proposed, would not be possible. Some commenters claimed this could result in a bottleneck that would effectively become a moratorium on OCS drilling. Given the other demands of the proposed rule, some commenters asserted that 3 years is a more feasible timeline for implementation of this requirement. Other commenters, however, requested that the BAVO certification requirements should not go into effect until 12 months after the initial BAVO list is published.

• *Response:* As previously discussed in part V.C of this document, BSEE has revised the final rule to extend the compliance dates for certain provisions, including those that require the use of a BAVO. Under the final rule, operators' APD will not be required to submit BAVO certifications under § 250.731 until one year from the date when BSEE publishes a list of approved organizations. BSEE anticipates that most of the current independent third-parties currently used by industry could become BAVOs; thus, one year will be sufficient for operators to make use of a BSEE-developed list of BAVOs suitable for this rulemaking.

Summary of comments: A commenter asked if BSEE approval as a verification organization is open for any company that applies.

• *Response:* Any verification organization that seeks approval and submits the information specified in § 250.732(a) to BSEE may be considered by BSEE for approval as a BAVO.

Summary of comments: A commenter suggested that BSEE should allow use of current verification companies whenever a BAVO is not available.

• *Response:* Under § 250.732, BSEE will not require the use of BAVOs until one year after BSEE establishes a BAVO list. After that occurs, there will not be any need to use other verification companies. BSEE expects many existing independent third-parties and verification companies to become BAVOs.

Summary of comments: Some commenters asserted that the requirements to use BAVOs for certification could create conflicts of interest and render the third-party neutrality concept ineffective. That is, if BSEE approves the verification organization, and the operators/contractors are required to hire them, neither BSEE nor the BAVO nor the operators would be independent of each other.

A commenter asserted that BAVOs provide BSEE with selective powers not generally associated with a regulatory organization in a free market system. Commenters recommended that BSEE remove/delete all references to BAVOs due to potential legal implications and restriction of trade.

- *Response:* BSEE disagrees with the suggestion that the BAVO approach will compromise third-party neutrality or effectiveness or is otherwise impermissible. To the contrary, approval of verification organizations by BSEE will ensure that the BAVOs are independent of the parties whose crucial equipment and processes the BAVO will review and evaluate. Other regulatory regimes throughout the world use similar systems.

Summary of comments: Some commenters also asked how BAVOs will work and what specific factual situations BAVOs would or would not be able to certify or verify under §§ 250.731(c) and (d) and 250.732 (*e.g.*, how will a BAVO be able to verify that a stack has not been compromised from previous service?).

- *Response:* These comments seek answers to hypothetical questions about how the rules may be implemented in very specific factual situations. It would be premature and speculative for BSEE to attempt to do so. A BAVO will need to certify or verify the matters specified in §§ 250.731 and 250.732, but those rules do not prescribe exactly how the BAVO must perform those tasks. Rather, the purpose of BSEE evaluating and approving verification organizations to serve as BAVOs is to ensure that they are knowledgeable and capable enough to perform these tasks without BSEE needing to prescribe in great detail how to do so under a very specific factual scenario.

What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components? (§ 250.732)

As provided for in the proposed rule, this new section creates a process for BSEE to identify BAVOs and sets out various situations that require verification or a report by a BAVO. Paragraph (a) clarifies that BSEE will develop and maintain a list of BAVOs on its public website, and that compliance with the BAVO-related provisions of the rule will not be required until 1 year after BSEE issues that list. Paragraph (a) also specifies the information (regarding qualifications) that applicants for inclusion on the BAVO list must submit; while paragraph (b) lists the types of actions (*e.g.*, shear testing) for which an operator must submit BAVO verification. Paragraph (c) of this section requires additional BAVO verifications for BOPs and related equipment associated with wells in an HPHT environment. Paragraph (d) requires an operator to submit to BSEE an annual MIA report prepared by a BAVO. These BAVO actions will help BSEE ensure that BOPs will perform as necessary to protect safety and the environment from losses of well control. BSEE has revised certain provisions of the proposed rule in final § 250.732 as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.732—Existing Quality Control Systems

Summary of Comments: Many comments asserted that operators already have adequate systems in place for quality control (*e.g.*, voluntary compliance with API Spec. Q1 or similar standards), to verify repeatability of testing, and/or to comply with existing requirements under BSEE's regulations for SEMS programs (including a requirement for SEMS program audits). Commenters suggested that these systems adequately address many of the same items subject to BAVO verification under proposed § 250.732, and thus, that BAVO verification of similar issues is unnecessary and overly burdensome.

- *Response:* BSEE does not agree that the BAVO-related requirements of § 250.732 are unnecessary; nor does BSEE agree that those requirements will not provide additional value, to justify the burdens on the operators, compared to existing voluntary industry practices and BSEE's other regulatory requirements. Third-party consultants hired by the operator for quality control, to confirm equipment testing repeatability, or for a SEMS audit do not address the specific BOP and well-control issues required by the present rule. Quality control and equipment testing repeatability are, as stated in the comments, addressed by several voluntary industry standards. While compliance with industry standards that are not incorporated in the regulations is voluntary, the BAVO verifications required by the final rule will document compliance with key regulatory requirements for ensuring that BOPs will perform as needed to protect safety and the environment. For example, the final rule requires verification of shear testing, pressure integrity testing, and related calculations for verifying that the equipment is suitable for the conditions under which it will operate.

In addition, while BSEE appreciates the value of operators' existing quality control programs, including those based on API Spec. Q1 or similar standards, BSEE cannot rely on such voluntary programs to provide the information or assurances that BSEE needs. As explained in the proposed rule, § 250.732 is necessary to ensure that BSEE receives accurate information regarding BOP systems so that BSEE may ensure the system is appropriate for the proposed use. In particular, the verification and documentation of such information by a BAVO would enhance BSEE's review of the information in APDs and APMs. (*See* 80 FR 21509, 21522.) BSEE believes that the importance and complexity of BOP systems warrant a thorough and regular assessment of the systems and verification that design, installation, maintenance, inspection, and repair activities for such systems are documented and traceable. The BAVO-related provisions in § 250.732 will serve this purpose, through independent engineering reviews to ensure that required testing is effective at ensuring the equipment will perform as designed under the conditions to which it will be exposed. (*See* 80 FR 21509.) Voluntary compliance with industry standards alone cannot provide BSEE with such assurances.

Similarly, BSEE believes the SEMS regulations are an important step toward building an offshore safety culture that includes oil and gas companies as well as their employees and contractors, and the SEMS rules will result in substantial safety and environmental protection improvements over time. However, the SEMS requirements are very different from, and serve different purposes than, the BAVO-related requirements. The SEMS regulations focus on creating internal safety and environmental management systems that will foster safety and environmental protection by ensuring that offshore personnel comply with policy and procedures identified in a facility's SEMS plan. The SEMS rules lay out largely performance-based elements that the SEMS plan must address in areas such as hazards management, inspections and maintenance, training, and quality assurance and mechanical integrity of critical equipment. (See § 250.1901.) However, the SEMS rules do not prescribe specific technical requirements that the plans must ensure are met. Nor is BSEE routinely informed of the specific results from actual implementation of the SEMS plan at a rig.

By contrast, BAVO verifications or reports under § 250.732 will provide BSEE with important information regarding, among other things: Actual shearing capabilities (through recognized testing protocols and analyses), and pressure integrity testing (*see* § 250.732(b)); comprehensive review of the BOP system demonstrating the performance and reliability of the equipment; and annual reports by the BAVO on mechanical integrity for BOPs used in certain high risk environments. BSEE needs the information that BAVOs will verify or create in order to ensure that effective and appropriate well-control equipment and procedures are actually in place to prevent or minimize future well-control events. BSEE cannot get that kind of information through operators' voluntary compliance with either industry standards or the SEMS regulations.

However, in response to commenters' suggestions that BSEE allow the continued use of independent third-parties to perform verifications (as required under provisions of the existing regulations that are being replaced by these final rules),[17] and to comments requesting additional time to comply with the BAVO requirements, BSEE has revised § 250.732(a) of the final rule. The revised paragraph will require that an independent third-party, meeting the same criteria as specified in former § 250.416(g)(1), perform the same functions that a BAVO must perform until such time as the operator uses a BAVO to perform those functions (*i.e.*, no later than 1 year after BSEE publishes a list of BAVOs).

Comments Related to Proposed § 250.732(a)—Timing of Compliance With BAVO Requirements

Summary of Comments: Many comments asserted a need for sufficient time to comply with the BAVO-related requirements after BSEE issues a list of BAVOs. Specifically, multiple comments addressed the need for time to select a BAVO and to have the BAVO implement the required verifications. These comments raised essentially the same concerns previously discussed with regard to BAVO certifications as required by § 250.731.

• *Response:* BSEE, as previously explained, has revised the final rule to extend the time required to comply with the requirements to utilize a BAVO until one year after BSEE publishes a list of BAVOs. BSEE has determined that this will provide enough time for operators to select a BAVO and for the BAVO to perform the required verifications. In the interim, for the reasons previously discussed, BSEE has revised final § 250.732(a) to require operators to use an independent third-party to provide the certifications, verifications, and reports that a BAVO must provide after the requirements to use a BAVO become effective.

Comments Related to Proposed § 250.732(a)—General Comments on BAVOs

Summary of Comments: Multiple comments raised the following issues: (a) BSEE is restricting industry's choice of third-parties by requiring use of a BAVO; BSEE should provide industry with the opportunity to comment on the intended detailed work scope for a BAVO; (b) industry must be provided with a means of recourse to BSEE on decisions made by BAVOs where there is a difference of opinion regarding the application or interpretation of a rule or standard; and (c) some of the proposed requirements imply that the BAVO may make recommendations on how to improve the fabrication, installation, operation, maintenance, inspection, and repair of operator equipment.

• *Response:* Concerning the comments on BSEE restricting industry's choice of third-parties by requiring use of a BAVO, BSEE is aware that the requirement to use BAVOs will impose some limits on the choices of third-parties. However, that is an unavoidable feature of any requirement that depends on the use of a third-party having relevant qualifications necessary to perform specific tasks, whether BSEE determines who meets those qualifications or the operators make those decisions themselves. In addition, for the reasons stated in the proposed rule, BSEE determined that it is necessary for each BAVO performing the important safety and environmental tasks specified in §§ 250.731 and 250.732 to be technically qualified, experienced and capable of performing the functions necessary for BSEE and the public, as well as the operators, to be sure that the BOP systems and equipment will function as intended. Therefore, in its oversight role, it is necessary that BSEE make the first decisions as to which third-parties are eligible to be used for these purposes, rather than leaving that decision entirely to the operators whose equipment and processes must be evaluated and verified to be suitable and capable of performing their intended functions.

In any case, BSEE will publish a list of BAVOs so that choices will be available to operators. BSEE expects that there will also be enough listed BAVOs that operators will be able to base their choices between BAVOs on various factors, such as experience, price, availability, and access to appropriate technology. After the initial BAVO list is published, BSEE will continue to evaluate other verification organizations that apply for approval as BAVOs and will refresh or supplement the list from time to time as necessary to ensure that choices continue to be available to operators.

Concerning the suggestion that BSEE should provide industry with the opportunity to comment on the detailed scope of the work that BSEE intends BAVOs to perform, the final rule, in §§ 250.731 and 250.732, provides the scope of the certifications and verifications that BAVOs must perform. As to how a BAVO will perform each specific task for a specific facility, the BAVO and the operator employing the BAVO will work together to determine the precise nature and execution of the work. BSEE expects that the BAVOs and operators will establish these parameters through the contracting process.

Concerning the comments that industry should have a means of recourse to BSEE on decisions made by BAVOs where there is a difference of opinion regarding application or interpretation of a rule or standard, several means exist for BSEE to resolve such differences of opinion. In the first place, BSEE expects the BAVO and the operator to communicate with each other and attempt to resolve any differences of opinion in a mutually acceptable way. However, if necessary, the operator may refer requests for an interpretation of a specific regulation, or a standard incorporated in the regulations, to BSEE for assistance. In addition, if it appears that there is a broader need for an interpretation to guide BAVOs and operators, BSEE will consider issuing a NTL, an Information to Lessees and Operators, or a similar notice of interpretation or guidance, as appropriate.

BSEE disagrees with the comments suggesting that the proposed requirements imply that the BAVO may make recommendations on how to improve the fabrication, installation, repair, etc., of operator equipment. The rule does not state or imply that a BAVO must or should make recommendations to an operator with respect to the equipment. However, BSEE does expect

[17] Former §§ 250.416(e) and (f), 250.515(c) and (d), 250.615(c) and (d), and 250.1705(c) and (d) require verifications of various aspects of drilling, completion, workover and decommissioning operations, respectively. Those requirements are superseded and replaced by the requirements of final § 250.731(c) and (d).

the BAVO process to help, over time, the industry to improve the performance of the equipment and to develop more and better testing protocols. (*See* 80 FR 21509.)

Comments Related to Proposed § 250.732(a)(1) Through (7)—Criteria for BAVOs

Summary of Comments: Multiple comments asserted that the criteria used to evaluate the technical knowledge of the BAVOs must be established in advance and be more detailed than the proposed criteria. A commenter also suggested that industry should be consulted in helping to identify qualified candidates. However, other commenters recommended that the regulation expressly require BAVOs to be independent of equipment manufacturers and operators.

• *Response:* BSEE disagrees with the comments calling for more detailed BAVO criteria. Proposed § 250.732(a)(1) through (6) (renumbered as § 250.732(a)(3)(i) through (vi) in the final rule) specified the criteria that BSEE would apply in evaluating the qualifications, caliber, and technical knowledge of each verification organization before deciding whether it should be approved. The commenters on this issue provided no additional detailed criteria for BSEE to apply in evaluating verification organizations, and BSEE sees no reason to add more criteria at this time.

In addition, BSEE disagrees with the suggestion that industry should be consulted in helping to identify BAVO candidates. As explained in the proposal, the purpose of the BAVO concept is to ensure that BOP equipment is monitored during its lifecycle by an ''independent third-party'' to verify compliance with the regulations, OEM recommendations, and recognized engineering practices. (*See* 80 FR 21522.) As explained in the proposed rule, a potential BAVO must apply to BSEE for approval, and must submit specific information and documentation demonstrating its qualifications and experience, as provided in § 250.732(a)(1) through (7). (*See* id. at 21510, 21522.) BSEE will then evaluate that specific information to determine whether the verification organization is qualified to carry out the BAVO-related tasks listed in § 250.732(b) through (d) and in other sections. If BSEE determines, based on the information submitted and BSEE's understanding of the specific tasks BAVOs must perform, that an organization is qualified to perform those task, BSEE will add that organization's name to the BAVO list.

Comments Related to Proposed § 250.732(b)(1)(i)—BOP Shearing Tests

Summary of Comments: Multiple commenters raised concerns with the proposed requirement in § 250.732(b)(1)(i) for shearing tests that demonstrate the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well. They asserted that many rigs do not currently have shearing capability that would conform to that requirement and cannot obtain such equipment within the 3 months provided by the proposed rule for compliance. As a result, many drilling operations could be shutdown. They requested that BSEE extend the requirement for shearing the exterior control lines (*e.g.*, wire-line) to 5 years.

• *Response:* BSEE agrees that more time may be necessary to allow installation on all BOPs of shear rams capable of shearing electric-, wire-, slick-lines to be used in the hole. However, BSEE does not agree that 5 years is necessary for compliance with this requirement. Although 5 years might be appropriate if no technology capable of meeting this requirement existed, BSEE is aware that some technology to meet this requirement already exists (and thus does not need to be newly developed after promulgation of this rule). Nonetheless, BSEE understands that significantly more than 90-days will be needed for all operators to obtain, modify (if necessary to meet specific circumstances), and install the technology. Therefore, BSEE has revised §§ 250.732(b)(1)(i) and 250.734(a)(1)(ii) in the final rule to extend the compliance date for demonstrating that the BOP can shear electric-, wire-, or slick-line until 2 years after publication of the final rule. This extended compliance date will allow sufficient time for operators to acquire and install appropriate equipment without causing any rig downtime.

Comments Related to Proposed § 250.732(b)(1)(ii)—BOP Shearing Tests

Summary of Comments: One comment was received on proposed § 250.732(b)(1)(ii), requiring a demonstration that the operator's shear testing at a facility that meets generally accepted quality assurance standards. The commenter stated that ''generally accepted quality assurance standards'' needs to be clarified, and recommended that BSEE provide examples of this requirement (*e.g.*, ISO 9001).

• *Response:* BSEE does not believe that revisions to the regulatory text are needed in response to this comment. The proposed language in § 250.732(b)(1)(ii) is intentionally general and performance-based so as to leave operators free to use testing facilities that meet generally accepted quality assurance standards. BSEE believes that operators are capable of identifying such standards, but if future experience under this provision demonstrates that operators need guidance to identify such standards, BSEE may provide appropriate guidance at a later date.

Comments Related to Proposed § 250.732(b)(1)(v)—BOP Shearing Capacity

Summary of Comments: Several commenters requested that BSEE revise proposed § 250.732(b)(1)(v)—regarding demonstration of the shearing capacity of the BOP—to clarify that the demonstration must be specific to the drill pipe to be used in the well.

• *Response:* BSEE disagrees with the suggested change to specify that this requirement applies only to the drill pipe used or to be used in the well, since that point is already stated in § 250.732(b)(1)(i), and the same limitation is implied throughout § 250.732(b)(1).

Comments Related to Proposed § 250.732(b)(1)(vi)—BOP Shearing Test Results

Summary of Comments: Several commenters requested that BSEE revise the proposed requirement in § 250.732(b)(1)(vi) that ''all [shear] testing results'' be provided to BSEE by changing ''all'' to ''relevant.''

• *Response:* BSEE agrees with the commenter and has revised final § 250.732(b)(1)(vi) by replacing ''all'' testing results with ''relevant'' testing results. This change will ensure that the testing data provided to BSEE is applicable and relevant to the specific shear testing issues covered by § 250.732(b)(1) and that other, non-relevant testing results, which could cause confusion, are not submitted.

Comments Related to Proposed § 250.732(b)(1)(iv)—Off-Center Pipe Shearing

Summary of Comments: Multiple commenters stated that proposed § 250.732(b)(1)(iv)—regarding off-center pipe shearing—was inconsistent with proposed § 250.734(a)(16), which requires operators to install shear rams that center drill pipe during shearing no later than 7 years from the publication of the final rule. One suggestion was to revise § 250.732(b)(1)(iv) as follows: ''Ensures that the test demonstrates off-center pipe shearing capability within the time period referenced in § 250.734(a)(16)(i).''

• *Response:* BSEE disagrees with the comment about the inconsistencies between the compliance timeframes for the two referenced sections. The requirement in § 250.734(a)(16) to center the drill pipe while shearing is important to help increase shearing capabilities and ensure effective shearing in an emergency. However, as discussed elsewhere, BSEE has determined that additional time is needed for such technology to continue to be developed, produced, acquired and installed, and thus proposed 7 years as a reasonable time to comply with that requirement. (*See* 80 FR 21510.) By contrast, the technology to perform off-center shearing is already in widespread use, and there is no reason to postpone the adoption of the testing requirements for that technology.

Comments Related to Proposed § 250.732(b)(1)(iii)—Shear Test Documentation

Summary of Comments: Several commenters stated that the requirement of § 250.732(b)(1)(iii)—for documenting that the shear testing provides a reasonable representation of field applications—should be in accordance with current industry standards only. This includes shearing the drill pipe with zero wellbore pressure and zero tension. The commenter asserted that there is a safety risk when shearing a drill pipe in the lab with high pressure in the wellbore and flowing conditions.

• *Response:* BSEE does not agree with the commenter that a change is necessary to § 250.732(b)(1)(iii). BSEE understands that the technological capabilities of shear testing are limited; however, BSEE also recognizes that advancements have been made to improve testing capabilities to better simulate field applications. Therefore, BSEE has not made any changes to this paragraph. BSEE expects all shear testing to be done in a safe manner to ensure personnel safety.

Comments Related to Proposed § 250.732(b)(2)(ii)—Pressure Integrity Testing

Summary of Comments: Several commenters stated that the proposed requirement in § 250.732(b)(2)(ii) that pressure integrity testing demonstrate that the equipment will seal at the RWP of the BOP pressure, should be revised because it could create potential confusion. One commenter also said that the test pressure should be MASP/MAWHP, or the RWP of the sealing preventer above the uppermost shear ram, whichever is lower.

• *Response:* BSEE disagrees with the comment that this paragraph is unclear or confusing as written. BSEE also disagrees with the recommended changes to this provision. The testing described in § 250.732(b)(2)(ii) is performed at a testing facility, while the commenter's suggested language apparently contemplates testing conducted on a rig.

Comments Related to Proposed § 250.732(b)(3)—Calculations—MASP

Summary of Comments: One comment was received from multiple commenters that the proposed requirement in § 250.732(b)(3) for calculations include shearing and sealing pressures that are corrected for MASP should be revised. The comment stated that MASP/MAWHP should be limited to the RWP of the preventer above the uppermost shear ram, because it is not possible to have more than the RWP of the preventer above the shear ram.

• *Response:* BSEE disagrees with the commenter's recommended revision. The requirements of § 250.732(b)(3) only apply to calculations identifying the sealing pressure for all pipe to be used in the well. The calculations are to be used to determine the applicability and use of the shearing components; it is the operator's responsibility to determine how the calculations are applied to the specific components on the rig. Therefore, no changes are necessary to this paragraph.

Comments Related to Proposed § 250.732(c)—Facility Access

Summary of Comments: Multiple commenters requested that BSEE revise § 250.732(c) with regard to a BAVO having access to any facility associated with the BOP system during the review process. The comments requested that BSEE change the wording of ''access to any facility'' to ''access to documentation.'' The comments asserted that this provision was too broad and implies that BAVOs have law enforcement rights.

• *Response:* BSEE disagrees. BAVOs must have access to the relevant facilities in order to perform the testing and certification functions necessary to ensure that BOPs function as intended to prevent well-control events. There is no basis for the suggestion that requiring operators to provide facility access to the BAVO—which the operator has retained to perform these functions on its behalf—confers any law enforcement authority on the BAVO.

Comments Related to Proposed § 250.732(c)(2)—Verification of BOP System Testing

Summary of Comments: One commenter suggested that the proposed requirement in § 250.732(c)(2)—for verification that designs of the BOP system and individual components have been proven in a testing process that demonstrates the equipment's reliability in a way that is repeatable and reproducible—be cross-referenced to appropriate validation testing required in industry specifications (*e.g.,* API Specs.16A/16C/16D).

• *Response:* BSEE disagrees with the commenter's suggestion that we reference specific industry standards in § 250.732(c)(2). This paragraph is setting general requirements and is intended to be broad enough to allow for flexibility in verifying the component designs without limitation to any specific existing standard(s).

Comments Related to Proposed § 250.732(c)(4)—API Spec. Q1

Summary of Comments: One commenter suggested that quality control and assurance mechanisms referred to in § 250.732(c)(4) require compliance with API Spec. Q1.

• *Response:* BSEE disagrees with the commenter's suggestion to reference specific industry standards in § 250.732(c)(4). This paragraph sets general requirements and is intended to be broad enough to allow for flexibility in verifying that the fabrication, manufacture and assembly of BOP components and the BOP system use appropriate quality control and assurance mechanisms, without limiting the choices of such mechanisms.

Comments Related to Proposed § 250.732(c)(4)—Quality Control and Assurance

Summary of Comments: One industry commenter stated that the proposed requirement in § 250.732(c)(4) that quality assurance and control mechanisms cover ''all contractors, subcontractors, distributors, and suppliers at every stage'' is overly broad and undefined. The commenter asserted that complying with such a broad requirement would take many years. The commenter suggested that BSEE revise this provision to read: ''The quality control, assurance requirements and material documentation specified by the industry standard(s) for the components and systems.''

• *Response:* BSEE does not agree. The commenter provided no explanation or support for its opinion or its recommended changes to the rule.

Therefore, BSEE has no basis to adopt the commenter's recommended change.

Comments Related to Proposed § 250.732(d)—MIA Report

Summary of comments: Multiple comments stated that the requirement in proposed § 250.732(d) for an annual MIA report for subsea BOPs, BOPs used in HPHT environments, and surface BOPs on floating facilities would be redundant and unnecessary and would not increase the safety or reliability of BOP equipment. The comments asserted that each item to be included in the MIA report is already covered by the operators' SEMS plans, as required by BSEE's SEMS rules, or by operators' compliance with API Standard 53 requirements. Commenters also noted that the proposed rule requires adherence to OEM training recommendations that do not exist.

- *Response:* BSEE does not agree that the MIA reporting requirement is redundant or unnecessary. As previously discussed, although some of the technical issues that must be covered in an MIA report under § 250.732(d) are related to certain issues that must be addressed in SEMS plans, there are also many differences between the contents of the MIA reports and SEMS plans. The primary purpose of the MIA report is to provide BSEE with the technical information that BSEE needs to carry out its responsibilities under OCSLA and part 250. By contrast, the purpose of the SEMS plans is to help the OCS industry and workforce to build a stronger safety culture and to improve safety and environmental performance through compliance with the policies and procedures in those plans.

Similarly, while there are some matters covered in an MIA report that are also covered under API Standard 53, there are significant differences and certain types of information required in the MIA report are not covered by API Standard 53.

The comment that the proposed rule would require compliance with non-existent OEM training recommendations does not warrant any change to the final regulation. It is already clear that § 250.732(d)(6) only requires compliance with any OEM training requirements that actually exist.

Summary of comments: Some comments asserted that proposed § 250.732(d)(6)—regarding verification in the MIA report that training for BOP personnel meets OEM requirements—would require adherence to OEM training recommendations that do not exist.

- *Response:* The proposed rule did not, and the final rule does not, state that an operator must provide training to BOP personnel that meets OEM training recommendations or requirements that do not exist; nor does BSEE intend that provision to be interpreted in that way. Accordingly, BSEE has modified final § 250.732(d)(6) to clarify that training must include "any applicable" OEM requirements.

What are the requirements for a surface BOP stack? (§ 250.733)

As provided for in the proposed rule, this section combines and revises several sections of the former regulations that established technical requirements for surface BOP stacks and related equipment. Paragraph (a) of this section specifies the point at which the surface BOP stack must be installed, sets minimum requirements for numbers and types of key surface stack components and equipment (*e.g.,* remote-controlled BOPs that include annulars, blind shear rams, and pipe rams), and specifies the shearing or closing and sealing capabilities that such equipment must have. If the blind shear ram could not cut electric-, wire-, or slick-lines under MASP an alternative cutting device must be on the rig floor during operations that can cut the wire before closing the BOP. Paragraph (b) sets additional requirements and related compliance dates for surface BOPs on floating production facilities. Paragraphs (c) and (d) establish requirements for choke and kill lines. BSEE has revised certain provisions in proposed § 250.733 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.733(a)—Risks of Manual Cutting Device

Summary of comments: A commenter was concerned that BSEE may have underestimated the risks (of a fire or explosion) associated with using a separate manual cutting device as an alternative cutting device, under proposed § 250.733(a)(1), during an emergency well-control situation where hydrocarbon vapors may be present on the rig floor. This commenter was also concerned that the speed and effectiveness of closing-in a well would be compromised by using a single blind shear ram and manual cutting device. Thus, this commenter asked that BSEE consider requiring a more robust, automated redundant blind shear ram closure system for all surface BOP systems.

- *Response:* BSEE does not agree with the recommended changes to the requirements for the alternative cutting device specified in paragraph § 250.733(a)(1). This provision will be a substantial improvement over the current regulations, which do not impose any requirements for cutting any electric-, wire-, or slick-line. BSEE is evaluating additional shearing rams for surface BOPs and other advanced technology that may be capable of severing everything in the hole; however, more research and data are needed before BSEE decides whether technology such as that recommended by the commenter should be added to the rules. If research or study reports or other information becomes available to BSEE that warrants additional requirements, BSEE may propose such a revision in a future rulemaking.

Comments Related to Proposed § 250.733(a)—Prescriptiveness of Requirements

Summary of comments: Two commenters claimed that the proposed requirements in § 250.733(a) would be too prescriptive; *i.e.,* that ram placements and configurations should be established by the operator based on a risk assessment.

- *Response:* BSEE does not agree with the suggested changes to paragraph § 250.733(a). This provision does not specify where the rams are to be placed and how they should be configured. Moreover, this paragraph simply restates the longstanding requirements of prior § 250.441(a), which describes the type of BOP components that must be in the BOP stack, but not how they must be configured.

Comments Related to Proposed § 250.733(a)—Compliance Timing

Summary of comments: A commenter recommended that BSEE revise the compliance dates for implementation of the requirements under paragraph (a), suggesting 3 years (rather than the proposed 3 months) to comply and recommending that an annual status report be submitted to BSEE until the rig is in compliance.

- *Response:* BSEE agrees that an extension of the proposed 3-month (from publication of the final rule) compliance date for § 250.733(a)(1) is warranted for certain elements, although the 3 years recommended by the commenter is unnecessary. As previously discussed (*see* part III of this preamble), BSEE is aware that some current technology is available to shear tubing with exterior control lines; accordingly, the effective date for shearing such tubing has been extended to 2 years (from publication of the final rule) in order to allow operators to acquire and install (and, if necessary, to develop new or alternative) equipment to meet the requirements. However, the commenter provided no support for modifying the compliance date for any other elements of § 250.733(a), nor is BSEE aware of any basis for doing so. Therefore, BSEE has not revised the compliance date for the remainder of § 250.733(a).

Comments Related to Proposed § 250.733(a)(1)—Shearing Requirements

Summary of comments: Commenters asked BSEE to confirm that it intended to propose the exclusions from the blind shear ram shearing requirements in proposed § 250.733(a)(1) for ''tool joints, bottom hole tools, and bottom hole assemblies that include heavy-weight pipe or collars.'' Although excluded in the regulatory text, the exclusions were not discussed in the preamble to the proposed rule.

• *Response:* BSEE understands that there is no such technology currently available that can shear such equipment. Additionally, if all of the shearing capability requirements of this rule are met, there is no need for the equipment to be able to shear equipment at the bottom of the hole. Accordingly, the proposed and final regulatory text for paragraph (a)(1) correctly excluded shearing requirements for tool joints, bottom hole tools, and bottom hole assemblies that include heavy-weight pipe or collars from shearing requirements was intended and was correctly included in the proposed rule, as well as in the final rule. The omission of any discussion of those exclusions in the preamble description of proposed § 250.733(a)(1) was inadvertent.

Comments Related to Proposed § 250.733(a)(1)—Shearing Under MASP

Summary of comments: A commenter was concerned about the proposed requirement that if the blind shear rams are unable to cut ''any electric-, wire-, or slick-line under MASP,'' an alternative cutting device must be used. The commenter asserted that the word ''any'' in that context is open-ended. The commenter suggested that the operator should be able to demonstrate that its blind shear rams can cut the lines intended for use rather than ''any'' possible lines.

• *Response:* BSEE does not agree with the commenter's apparent concern about paragraph § 250.733(a)(1). The commenter did not fully explain its concerns, but BSEE assumes the commenter believed the provision required that the ram be capable of shearing any possible line. However, the proposed (and final) regulatory text simply refers to the electric-, wire-, or slick-line ''that is in the hole,'' not to hypothetical lines that are not in the hole.

Comments Related to Proposed § 250.733(a)(1)—Shear Rams

Summary of comments: Another commenter recommended adding language to paragraph § 250.733(a)(1) to the effect that if the BOP stack has dual shear rams, and the lower shear ram can shear all drill pipe, then the upper shear ram only needs to seal against MASP, not to exceed the RWP of the preventer located directly above the shear ram.

• *Response:* BSEE does not agree with adding the language the commenter suggested. Since § 250.733(a)(1) does not require dual shear rams to be used in a surface BOP stack, the commenter's suggested language appears to involve a hypothetical scenario outside the scope of the rule.

Comments Related to Proposed § 250.733(a)(2)—Exterior Control Lines

Summary of comments: Commenters recommended adding more exclusions to the proposed requirement that the pipe rams be able to close and seal on the tubular body of any drill pipe, workstring, and tubing under MASP. Specifically, the commenters asked that BSEE exclude pipe bodies with exterior control lines. Commenters emphasized that closing a ram preventer on tubing and exterior control lines (*e.g.,* flat packs) is not currently achievable, nor is it a realistic expectation for the near future. The commenters claimed that since it is not possible to comply with this provision, the industry would be shut down in the Gulf of Mexico. Commenters suggested use of a risk assessment to identify additional mitigation measures or requiring the shear ram to be able to shear and seal the tubular with the items attached to the outside of the pipe.

• *Response:* As previously discussed, BSEE agrees that pipe rams currently cannot completely seal around tubing with exterior control lines. An annular is the only BOP component able to seal around tubing with exterior control lines and is only used for a low pressure situation, which is usually the case when running tubing with exterior control lines. Accordingly, BSEE has revised final paragraph (a)(2) to clarify that pipe rams are not required to seal tubing with exterior control lines and flat packs.

Comments Related to Proposed § 250.733(a)—Pipe Rams and MASP

Summary of comments: Another commenter recommended removing the requirement from § 250.733(a) that pipe rams must be able to close and seal under MASP, since § 250.730(a) already establishes that the BOP (including pipe and variable bore rams) must have an RWP greater than MASP, and thus the two provisions would effectively be redundant.

• *Response:* BSEE is not revising paragraph (a) as the commenter suggested. The capability of pipe rams to close and seal under MASP is important because the MASP predicts the highest pressure to be encountered at the surface of the well and is used in ensuring that BOPs can function as intended. Although § 250.730(a)(3) establishes essentially the same requirement for all BOPs, reiterating the requirement in § 250.733(a)(2) for surface BOPs emphasizes the importance of this capability without imposing any additional burden on the operator.

Comments Related to Proposed § 250.733(b)—Surface Dual Shear Rams

Summary of comments: Several commenters asserted that BSEE should not require dual shear rams on surface BOPs on any floating production facility. Other commenters requested that BSEE conduct a full risk assessment of the impact of such a dual shear ram requirement before making it part of a final rule. They asserted that the negative consequences (related to weight, height and other structural limits on the facility) of adding such capabilities might increase rather than reduce risks.

Other comments stated that the rule is not clear about the requirements for existing floating production facilities with surface BOP stacks. Some recommended that BSEE allow ''grandfathering'' for existing and under-construction facilities, since the proposed requirements could create feasibility issues or additional costs that could make continued activity on such rigs economically unviable. Some commenters also recommended that BSEE allow operators to submit a risk assessment for each existing floating facility to determine whether the facility needs dual shear rams to reduce risk and allow those facilities to ''opt-out'' of the requirement (as provided in API Standard 53).

• *Response:* BSEE disagrees with the suggestions that the dual shear ram requirement for surface BOPs on floating production facilities be eliminated from the final rule altogether. As indicated in the proposed rule, § 250.733(b) is consistent with BSEE policy that surface BOPs on floating production facilities (like subsea BOPs) generally present higher risks than surface BOPs on fixed facilities. (*See* 80 FR 21522.) In addition, BSEE believes that overall performance of shearing equipment must improve over the longer term to ensure that the equipment can successfully shear a drill stem in an emergency. (*See* 80 FR 21509.) BSEE also believes that the industry is already moving toward eventual use of dual shear rams in surface BOPs on new floating production facilities.

For the same reasons, BSEE disagrees with the recommendation that BSEE do a risk assessment to justify the dual shear ram requirement or allow operators with surface BOPs on floating facilities to opt-out of the requirement if they perform a risk assessment. BSEE already addressed the latter suggestion in the proposed rule in connection with the dual shear ram requirement for subsea BOPs, and stated that an operator whose circumstances make the dual shear ram requirement infeasible can seek approval for alternative equipment or procedures under current § 250.141. (*See* 80 FR 21509–21510.)

However, BSEE understands several of the practical concerns related to applying the dual shear ram requirement to existing facilities. For example, BSEE agrees that the dual shear ram requirement, if applied to existing floating production facilities, or facilities under construction or in advanced stages of development, potentially could have negative personnel safety and structural impacts due to the added weight of the dual shear ram equipment and to the height and structural limits of those facilities. Accordingly, BSEE has revised final paragraph (b)(1) to apply the dual shear ram requirements to surface BOPs that are ''installed'' on floating facilities 3 years after publication of the final rule.[18] In effect, this means that surface BOPs on floating production facilities that exist now, or facilities that are installed on the OCS in the near-term, will not need to meet the dual shear ram requirement unless those BOPs are removed or replaced 3 or more years after the rule is published.[19] This 3-year compliance period will give the industry adequate time to plan, design, and develop surface BOP equipment that can meet the dual shear ram requirement on new floating production facilities.

Final § 250.733(b)(1) reasonably balances the practical concerns related to requiring dual shear rams on BOPs at existing floating facilities, or those to be constructed in the near-term, with the importance of improving the capabilities of surface BOPs on such facilities in the longer term. In fact, existing floating production facilities generally are less likely to have an event requiring a dual shear ram BOP, given that the majority of such facilities are located in depleted fields, with lower pressures due to ongoing production from those fields.[20]

Comments Related to Proposed § 250.733(b)(2)—Dual Bore Risers

Summary of comments: Comments on § 250.733(b)(2) focused on the meaning of the proposed requirement for dual bore risers on existing facilities. Commenters requested clarification that existing facilities currently using single bore strings may continue to do so. They noted that there are currently many single bore risers being used successfully on existing facilities, which should not be required to install new dual bore riser systems. Some commenters argued that this would present significant feasibility issues, with substantial economic consequences, but without significant safety benefits. A commenter also suggested that there are other safety precautions (such as dual barriers) that can improve safety without converting single bore risers to dual bore. In addition, some comments recommended changing the terminology from ''dual bore riser configuration'' to ''dual casing configuration'' to better align with the terminology used in industry.

- *Response:* BSEE does not agree that it is necessary to revise the dual bore riser requirements in paragraph § 250.733(b)(2). The commenters' concerns apparently are based on the misinterpretation that BSEE intended to require that all single bore risers be converted to a dual bore riser configuration. That was not BSEE's intention, as is evident from a careful reading of the proposed rule. The language in proposed, and now final, § 250.733(b)(1) applies only to risers installed after the effective date of the final rule (*i.e.,* 90 days from the date the final rule is published). If any operator already has existing plans to install a single bore riser after the final rule takes effect, the operator should contact BSEE and, if necessary, may request approval for alternative compliance under § 250.141.

BSEE also has not made the requested change from ''dual bore riser'' to ''dual casing'' since ''dual bore riser'' is an established and well-understood industry term.

Comments Related to Proposed § 250.733(b)(2)—Most Extreme Conditions

Summary of comments: Another commenter recommendation was to change the requirement to design for the ''most extreme'' conditions to a requirement to design for ''anticipated'' operating and environmental conditions. A commenter also requested that BSEE clarify that monitoring of the annulus between the risers means monitoring for pressure during operations.

- *Response:* BSEE agrees with this comment and has revised § 250.733(b)(2) by removing the term ''most extreme'' and replacing it with ''maximum anticipated,'' and added to paragraph § 250.733(b)(2)(i) that the riser must be monitored for pressure during operations.

Comments Related to Proposed § 250.733(c)—Side Outlet Valves

Summary of comments: A commenter recommended deleting the proposed requirement for side outlet valves to hold pressure in both directions, stating that there is no scenario under which these valves would see pressure in a surface application. The commenter asserted that this requirement for two-way valves should only apply to subsea BOPs and recommended that BSEE should revise the text for surface BOPs to only require that side outlet valves be able to hold pressure from the direction of flow.

[18] The revised language of final § 250.733(b)(1) also clarifies that existing floating production facilities do not need to retrofit or replace their BOPs in order to meet the dual shear requirement in 5 years, as the proposed language might have implied by its cross-reference to the dual shear ram requirement for subsea BOPs in proposed § 250.734(a)(1), which included a 5-year compliance date for those subsea BOPs.

[19] The requirement that surface BOPs installed 3 or more years after publication of the final rule must comply with the requirements of § 250.734(a)(1) does not extend the 5-year compliance date for dual shear rams as specified in § 250.734(a)(1). Specifically, any surface BOP installed between 3 years and 5 years after publication of the final rule must comply with the dual shear ram requirement no later than 5 years after publication of the final rule; any surface BOP installed 5 or more years after publication of the final rule must comply with the dual shear ram requirement when the surface BOP is installed.

[20] In addition, there are large amounts of offset well data for those existing facilities in depleted fields (due to the multiple wells previously drilled into the same geologic formations and reservoirs), which allows for better prediction of drilling parameters. Similarly, because of the prior production of the reservoirs at such facilities, the reservoir parameters and characteristics are generally well established.

• *Response:* BSEE does not agree with these comments. BSEE understands that side outlet valves are already in use and on surface BOPs are normally designed to hold pressure from both directions. Thus, there is no factual basis to revise this provision.

Comments Related to Proposed § 250.733(d)—Remote-Controlled Valve

Summary of comments: A commenter emphasized that, in an emergency case, a remote-controlled valve on a kill-line is easier and faster to access and operate. The commenter recommended that BSEE require that the valve on such lines be capable of both remote and manual operation if power for a remotely operated valve is not available, instead of the proposed language allowing the operator to use either a manual valve or remotely controlled valve.

• *Response:* BSEE disagrees with the suggested change. Due to the functions and intended use of the kill line, remote operation is not necessary, although the operator has the option to use both manual and remote operated valves.

Comments Related to Proposed § 250.733(e)—Hydraulically Operated Locks

Summary of comments: Commenters raised several concerns about the proposed requirement to install hydraulically operated locks on surface BOP stacks. Some commenters suggested deleting the requirement altogether; others suggested only requiring hydraulic locks on all surface BOPs on HPHT wells. Commenters asserted that this technology is not available for a majority of surface BOP systems and that there is no technical basis to require hydraulically operated locks on all surface BOPs. Commenters suggested, as an alternative, revising the requirement to ensure that BOP ram locks are in working order and accessible. Some commenters asserted that, while hydraulically operated locks remove the operator from the vicinity, and thus may provide more protection for some rig personnel than manually operated locks, they are not as reliable as manual locks, which are simpler in design.

Commenters also pointed out that, in a catastrophic well-control incident, the ability to charge or recharge the hydraulic closing unit may be lost. In addition, commenters also raised concerns regarding the timing and costs related to the proposed requirement, stating that compliance within 3 months would not be achievable for rigs that do not already have hydraulically operated locks and the necessary control systems. Commenters stated that, depending on the timing of the requirement, manufacturing, delivery, and installation of this equipment could lead to downtime for drilling rigs with surface BOPs. Commenters stated further that OEMs would not have the inventory on shelves to fulfill orders within 90 days.

Some commenters suggested an effective date 3 years after publication of the final rule, while others suggested that 5 years would provide enough time to design and manufacture any new components, procure and install, and obtain testing and verification by a BAVO. One commenter suggested that, if BSEE extends the compliance date, it could require an annual status report to BSEE until rigs are in compliance.

• *Response:* BSEE has deleted proposed § 250.733(e) from the final rule, since final § 250.735(g) adequately addresses the locking requirements for surface BOPs, and the circumstances covered by proposed § 250.733(e) do not warrant an additional requirement at this time. As described later in this document, BSEE has also revised final § 250.735(g) based on comments concerning both proposed § 250.733(e) and proposed § 250.735(g).

Comments Related to Proposed § 250.733(f)—BOP Repair Certification

Summary of comments: One commenter objected to the proposed requirement that a BAVO certify that it has reviewed repairs to a surface BOP in an HPHT environment and that the BOP is fit for service, pointing out that this provision is redundant with proposed § 250.738(b). Other commenters raised other concerns with, and requested other changes to, proposed § 250.733(f), including claiming that the proposed regulation inappropriately places the primary responsibility for verifying repairs on the BAVOs, instead of the operator.

• *Response:* BSEE agrees that proposed § 250.733(f) would be redundant with § 250.738(b); therefore, BSEE has deleted paragraph (f) from § 250.733 in the final rule.

What are the requirements for a subsea BOP system? (§ 250.734)

As described in the proposed rule, this section combines and revises provisions of former sections that established requirements for subsea BOP systems. Paragraph (a) requires dual shear rams and specifies the shearing requirements as well as requirements for the BOP control system, subsea accumulator capacity, ROV intervention capabilities, personnel training, and certain BOP equipment and capabilities. Paragraph (b) establishes procedural and testing requirements for resuming operations after operations are suspended to make repairs to the subsea BOP system. Paragraph (c) sets out APD requirements related to drilling a new well with a subsea BOP. BSEE has revised certain provisions in proposed § 250.734 in the final rule as discussed in the comment responses for this section and in parts V.B.2, V.B.5, and V.C of this document.

Comments Related to Proposed § 250.734—Risk-Based Approach

Summary of comments: Commenters stated that proposed § 250.734 uses overly prescriptive language, similar to the language used in the proposed BOP surface stack requirements. They also asserted that the proposed rule would increase the minimum equipment requirements beyond API Standard 53 and seek to introduce one-size-fits-all configurations. Commenters suggested re-writing the proposed rules with a risk-based approach that would enable BSEE to create a set of rules that could meet the desired intent without creating a number of unintended side effects. They assert that a risk-based approach would also be more suited to the constant evolution of drilling processes and would encourage technological innovation and efficiency.

• *Response:* BSEE recognizes the advantages and disadvantages of both approaches and understands that each approach can be effective and appropriate for specific circumstances. As explained in the proposed rule, this rulemaking uses a hybrid approach incorporating prescriptive requirements, where necessary, as well as many performance-based requirements. (*See, e.g.,* 80 FR 21509.) BSEE believes that this provision, as promulgated in the final rule, strikes the appropriate balance between prescriptive and performance-based requirements. The final provision is intended to ensure that subsea BOP systems include, at a minimum, certain types of components and processes that, based on BSEE's experience and analyses of past incidents, will help prevent future blowouts. However, § 250.734(a) does not mandate a one-size-fits-all approach. To the contrary, the final rule allows operators to exceed the prescribed requirements (*e.g.,* to use more than the required 5 remotely-controlled, hydraulically operated BOPs) if the operators wish to do so. Nor does this provision mandate the use of any manufacturer's equipment or otherwise discourage the development of new and better technology that will meet or exceed the requirements of the rule.

BSEE expects equipment manufacturers, operators and others to continue exploring and developing new, more efficient ways to meet these requirements.

Comments Related to Proposed § 250.734(a)—Device Connections

Summary of comments: A commenter asserted that the table in § 250.734(a)—listing requirements for operating with a subsea BOP—does not address connections between devices in the BOP stack, or methodologies for disconnection and/or reassembly or capping or containment points on those devices. The commenter stated that BSEE must address points of connection between the devices and capping and containment points to reduce the uncertainty of the procedures used in the event of failure. The commenter recommended that BSEE include a new section describing equipment and/or devices used to connect each component in the BOP stack, and a separate section describing capping and containment points and methods at all such locations on the BOP stack.

• *Response:* BSEE disagrees with the commenter that capping or containment points should be included in this section and has not made the suggested changes to paragraph (a). Containment requirements are covered adequately under proposed and final § 250.462.

Comments Related to Proposed § 250.734(a)—MASP

Summary of comments: Some commenters questioned BSEE's use of MASP in this section, asserting that MASP is not the appropriate industry term for subsea BOPs. They recommended using MAWHP, as defined in API RP 96 and API Standard 53.

• *Response:* As previously explained in connection with similar comments on § 250.730, MASP must be defined for the specific operation, and for a subsea BOP, the MASP must be taken at the mudline, as explained in § 250.730(a). For subsea BOPs, MASP taken at the mudline is the same as MAWHP. BSEE uses the term MASP in its existing regulations and disagrees with the suggestion that it would cause confusion in this context.

Comments Related to Proposed § 250.734(a)—Compliance Timing

Summary of comments: Multiple commenters expressed concerns about the compliance dates associated with this section and provided examples of why an extended compliance date is necessary. The aspects of the provisions that were of most concern included the lack of technology needed for shearing flat packs, slick-line, and other exterior control lines; procurement of additional accumulators needed for the closure of dual shear rams; installation of ram position indicators; and pipe centering capabilities. Although many commenters suggested that a 5-year implementation timeframe would be acceptable, others suggested longer timeframes for certain provisions.

• *Response:* BSEE agrees that there are some provisions in § 250.734(a), and other sections of this rule, for which operators will need more time for compliance than proposed. Accordingly, the final rule extends the compliance dates for specific requirements under paragraph (a)(1) as well as for the specific requirements under paragraphs (a)(1)(ii), (a)(3)(iii), (a)(15), and (a)(16)(i). More detailed discussion of the extended compliance timeframes is provided in part III of this preamble.

Comments Related to Proposed § 250.734(a)—Surface Casing Setting Point

Summary of comments: A commenter stated that proposed § 250.734(a) was unclear as to what conditions would lead the District Manager to require an operator to install a subsea BOP before reaching the surface casing setting point. This commenter asserted that prematurely installing a subsea BOP and shutting in on a kick before installation of surface casing would increase the risk of broaching to the seafloor.

• *Response:* BSEE clarified final § 250.734(a) by stating that the subsea BOP system must be installed before conducting operations if the well is already deepened beyond the surface casing setting point. Other situations that might require installation of the BOP below the conductor casing will be decided on a case-by-case basis by the District Manager. It would be premature to speculate on specific circumstances that would warrant such a decision, but the District Manager would certainly take into account whether installation of the BOP is likely to cause a broach or other increased hazard. If an operator has any concerns or questions about a specific factual scenario, it may contact the appropriate District Manager for assistance.

Comments Related to Proposed § 250.734(a)(1)—Compliance Timing

Summary of comments: A commenter observed that while BSEE proposed requiring a second blind shear ram for some BOPs, the rule would also allow 5 years for operators to implement this critical safeguard. Another commenter stressed that given the importance of dual blind shear rams to offshore drilling safety, all current and future blowout preventers should be equipped with these devices, and BSEE should reduce the time required for compliance with this provision.

• *Response:* As provided in the proposed rule (*see* 80 FR 21509–21510), BSEE agrees that the dual shear ram requirements are important to improving safety and environmental protection, consistent with recommendations arising from the *Deepwater Horizon* incident. However, the existing regulations did not require dual shear rams. BSEE believes that operators generally follow API Standard 53 regarding when dual shear rams should be used, based on the BOP classification. BSEE is aware that not all subsea BOPs have dual shear rams yet, and that acquiring and installing such equipment presents significant practical, technical and economic challenges. Accordingly, as discussed previously in the proposed rule (*see* 80 FR 21511) and this document, BSEE determined that 5 years is an appropriate timeframe for operators to obtain and install the necessary equipment for all subsea BOPs.

Comments Related to Proposed § 250.734(a)(1)—Dual Shear Rams

Summary of comments: Commenters raised various concerns about the proposed requirement for dual shear rams and the placement of BOPs. A commenter stressed that OEM equipment limitations restrict shear and seal capability of blind shear rams, and suggested that the regulations follow section 7.6.11.7.11 of API Standard 53, which states that ''[i]f a single ram is incapable of both shearing and sealing the drill pipe or tubing in use, the emergency and secondary systems shall be capable of closing two rams; one that will shear and one that will seal wellbore pressure.''

• *Response:* BSEE does not believe that one shear ram can ensure the ability of a subsea BOP to shear a drill string in the event of a potential emergency. The various investigations of the *Deepwater Horizon* incident recommended increasing the shearing capabilities of the BOP, including the use of dual shear rams on subsea BOPs. BSEE determined that use of dual shear rams would increase the likelihood that a drill string can be sheared, and ensures the well can be shut in and secured, by requiring that a shearable component is opposite a shear ram. BSEE also determined that merely requiring compliance with API Standard 53, which includes a procedure for ''opting-out'' of the dual shear ram provision, cannot provide the same level of assurance. (See 80 FR 21510–21511.) If there are unique circumstances that prevent the use of dual shear rams, operators would be able to apply for the use of alternative procedures or equipment under existing § 250.141.

Comments Related to Proposed § 250.734(a)(1)—Existing Wells

Summary of comments: A commenter remarked that the requirements in this section are reasonable for new wells, but that it may be appropriate to allow 4-ram BOPs on some existing wells with older wellheads. The commenter also said that the use of heavier/taller BOP stacks may potentially induce higher bending moments on the wellhead and BOP stack that will reduce the overall safety provided by the BOP.

• *Response:* BSEE disagrees with the comment about allowing a 4-ram BOP on existing wells with older wellheads. BSEE determined that a 5-ram BOP is appropriate due to the high potential of a significant well-control event, including at facilities with older wellheads. However, if there are unique circumstances (such as a concern with potentially higher bending moments on some older wellheads) that might warrant the use of a 4-ram BOP for a specific well, operators would be able to apply for the use of alternative procedures or equipment under existing § 250.141.

Comments Related to Proposed § 250.734(a)(1)—Shear Ram Placement

Summary of comments: Commenters asserted that the proposed requirement for the placement of non-sealing shear rams below the sealing shear rams conflicts with API Standard 53. Some comments suggested that BSEE revise paragraph (a)(1) to provide that any non-sealing shear ram must be installed below at least one sealing shear ram. Others recommended that the operators use a documented risk assessment to establish the fixed ram configuration as provided by API Standard 53. A commenter noted that there are rigs where 3 shear rams with casing shears are installed between two blind shear rams and in many instances the casing shear in the middle is the best configuration. Another commenter noted that it may be preferable to have a casing shear ram in between two sets of blind shear rams.

• *Response:* BSEE agrees with the commenter about requiring that any non-sealing shear ram must be installed below at least one sealing ram. This provides flexibility for sealing the well after shearing with non-sealing shear rams. The pipe can fall in the hole if not hung off, or the pipe can be lifted clearing the upper sealing ram. Accordingly, BSEE has revised final paragraph (a)(1)(ii) to read ''[a]ny non-sealing shear ram(s) must be installed below a sealing shear ram(s).''

However, BSEE is not requiring a risk assessment by the operator as the method for determining the order of the minimum requirements for one blind shear ram and one shear ram. If multiple redundant shearing rams are included, BSEE recommends a risk assessment, but one is not required. If there are unique circumstances that indicate that some configuration other than those specified in this paragraph may be warranted, operators would be able to apply for the use of alternative procedures or equipment under existing § 250.141.

Comments Related to Proposed § 250.734(a)(1)(i)—Exterior Control Lines

Summary of comments: Some commenters recommended adding an exclusion from the pipe ram sealing requirement in paragraph (a)(1)(i) for sealing on pipe with exterior control lines and umbilicals attached.

• *Response:* As discussed previously in this document, BSEE agrees with the comment about pipe rams not being able to seal around tubing with exterior control lines and flat packs. An annular is the only BOP component able to seal around tubing with exterior control lines and an annular is usually used for a low pressure situation, which is usually the case when running tubing with exterior control lines. Thus, BSEE revised paragraph (a)(1)(i) in the final rule to exclude tubing with exterior control lines and flat packs from the pipe ram sealing requirement, but requiring that (within 2 years) the shear rams be able to cut and seal the tubing with exterior control lines in the hole.

Comments Related to Proposed § 250.734(a)(2)—Dual-Pod Control System

Summary of comments: Commenters stated that the proposed rule prescriptively dictates that all subsea BOPs must have a dual-pod control system. They asserted that API Standard 53 adequately addresses redundancy of these systems without requiring all subsea BOPs to have dual-pod controls. A commenter also asserted that this provision would tie the industry to the prescribed current methodology without room to change or improve, and suggested that BSEE revise § 250.734(a)(2) to require subsea BOPs to ''[h]ave a fully redundant subsea control system to ensure proper and independent operation of the BOP system.''

• *Response:* BSEE agrees with the comments suggesting that the proposed requirement for dual-pod controls could have proven unduly restrictive, and that requiring redundant pod controls would provide more flexibility and room for improvement while providing at least as much protection as the proposed language. Accordingly, BSEE has revised final § 250.734(a)(2) by replacing ''dual pod control system'' with ''redundant pod control system.'' This change will also align the pod requirement in the regulations with the language of API Standard 53.

Comments Related to Proposed § 250.734(a)(3)—Fast Closure of BOP Components

Summary of comments: Commenters asked BSEE to clarify the requirements under proposed paragraph § 250.734(a)(3), related to ''fast closure of the BOP components'' and ''operate all critical functions.'' They indicated that BSEE did not define the terms ''fast closure'' and ''critical functions'' in the rule, noting that these terms are defined in API Standard 53.

• *Response:* Although the API Standard 53 definition of ''fast closure'' is one appropriate way to understand this term, it is not the only possible appropriate way. Thus, BSEE does not believe it is necessary to limit the meaning of ''fast closure'' in the regulations to the API Standard 53 definition. However, BSEE agrees with the commenter about the possibility of confusion and the need to define ''critical functions.'' Accordingly, BSEE revised final § 250.734(a)(3)(i) to specify that the critical functions are to ''[o]perate each required shear ram, ram locks, one pipe ram, and disconnect the LMRP.'' These critical functions are the same as those defined in API Standard 53.

Comments Related to Proposed § 250.734(a)(3)(i)—Subsea Accumulator Capacity

Summary of comments: Commenters also questioned the proposed requirement in § 250.734(a)(3)(i) for additional subsea accumulator capacity in case of the loss of power fluid connection to the surface. They emphasized that if there is a loss of the power fluid connection to the surface, then there also will probably be a loss of control from the surface. In that case, there would be no logical reason to require accumulator capacity to operate all choke and kill outlet valves.

• *Response:* BSEE agrees with the comment and has removed the reference to choke and kill side outlet valves, replacing it with a reference to ram locks, in final § 250.734(a)(3). This change is also consistent with the operations of critical functions.

Comments Related to Proposed § 250.734(a)(3)(iii)—Dedicated Independent Accumulator Bottles

Summary of comments: Commenters requested clarification of the intent and scope of the requirement in proposed § 250.734(a)(3)(iii) for ''dedicated independent'' accumulator bottles, located subsea for the autoshear, deadman, and EDS systems. Commenters asserted that this is a major deviation from API Spec. 16D and API Standard 53, which allow surface accumulator bottles to contribute to the EDS sequence. Complying with the proposed requirement would mean locating additional accumulator bottles on the subsea BOP stack, which commenters stated would pose practical and technical concerns due to inherent space limitations for subsea BOP systems, and could also exceed the capacities of the BOP crane, BOP frame, rig substructure, and BOP carts. Also, commenters asserted that more subsea accumulator bottles could both impede the ROV from seeing areas of the stack critical to troubleshooting during abnormal situations and create additional leak paths. In addition, commenters noted that the extra accumulator bottles would have to be removed each time the BOP is serviced, increasing safety risks from handling the bottles. As an alternative to the proposed requirement, commenters suggested that BSEE require one subsea accumulator bank, to be shared by autoshear, deadman, EDS, acoustic and other critical functions, as provided by API Standard 53.

Commenters also expressed concerns about the proposed timeframe (3 months from publication of the final rule) for complying with the new accumulator requirements, given design and engineering issues and potential problems with acquiring and installing sufficient accumulator bottles and related equipment. Most of those commenters stated that 5 years would be an appropriate timeframe for overcoming those problems.

• *Response:* BSEE agrees with many of the commenters' concerns, and has revised final § 250.734(a)(3) to clarify that subsea BOP accumulators must have enough capacity to provide pressure for critical functions, as specified in final § 250.734(a)(3)(i), and must have accumulator bottles that are dedicated to, but may be shared between, autoshear and deadman functions. The final rule does not require dedicated capacity for the EDS. These clarifications would eliminate most of the concerns about having to locate additional bottles subsea. BSEE also agrees that the proposed timeframe for compliance would be inadequate, even for the revised subsea accumulator requirements, given the need to design, develop, and implement solutions to the potential structural and engineering problems associated with acquiring, storing, and installing new accumulator bottles and related equipment. Accordingly, after review of the comments, BSEE has revised the compliance date for the accumulator requirements in paragraph (a)(3)(iii) to 5 years after publication of the final rule, as suggested by several commenters. This change also corresponds to the proposed (now final) 5-year compliance date for the final dual shear ram requirements, which likely would be the first time that the new subsea accumulator requirements would be needed in the event of an emergency. Thus, extending the compliance date for § 250.734(a)(3)(iii) would not adversely affect safety or the environment compared to the proposed rule. For a more detailed discussion of the accumulator revisions, see part V.B.2 of this document.

Comments Related to Proposed § 250.734(a)(3)(ii)—Subsea Accumulator Capability

Summary of comments: Commenters requested clarification of the requirement in proposed § 250.734(a)(3)(ii) for subsea accumulator capability to deliver fluid to each ROV function. A commenter recommended that BSEE allow alternative options, such as independent accumulator bottles to supply the hydraulic power. Commenters noted that these systems can be used in conjunction with the ROV flying leads. Commenters also suggested that, instead of being required for ROVs, the primary purpose of subsea accumulator bottles should be to deliver fluid under pressure to provide fast closure of the components in an emergency situation. Also, commenters asserted that ROVs themselves should be able to recharge the bottles to perform other functions if necessary.

• *Response:* BSEE does not agree that the suggested changes to § 250.734(a)(3)(ii) are necessary. This provision does not specify or limit the methods or devices that could be used to provide the necessary fluid to each ROV function. The ROVs must be capable of receiving the fluid from the accumulator, but BSEE is not restricting the use of other options, such as sand units. The rule simply requires that the subsea BOP have the capability of delivering the fluid to each ROV function.

Comments Related to Proposed § 250.734(a)(4)—ROV Intervention Capability

Summary of comments: Commenters raised several concerns with the proposed requirement that subsea BOPs must have ROV intervention capability. Some commenters emphasized that the primary purpose of ROV intervention capability (hot stab) should be to secure the well and unlatch the LMRP, if required. The commenters claimed that the proposed new requirements for ROVs will require considerably more ROV panels and functions. This will add leak points and test points, thus reducing the overall reliability of the system, reducing the availability of ROV access, reducing access for maintenance activities on the stack, and increasing the complexity of the BOP system. The commenters asserted that this will lead to increased maintenance costs. They also indicated that it will result in extra time and safety risks for ROV operators (*i.e.,* from firing the wrong function due to the increased number of ROV functions). Commenters also asserted that, due to likely equipment delivery delays, implementation of this regulation would require extended periods of downtime for operating rigs. Commenters noted that this paragraph exceeds the critical functions provisions in API Standard 53. These commenters recommended that BSEE revise this provision to refer to API Standard 53 for defining critical functions for ROV capabilities.

• *Response:* BSEE agrees with the comment that the proposed rule would require adding significant new ROV functions, and that API Standard 53 provides an appropriate description of critical ROV functions (such as opening and closing each shear ram, and LMRP disconnect). Limiting the number of functions required for the ROVs will significantly decrease the possibility of creating new leak paths, help reduce complexity of the BOP system, and minimize any rig downtime for equipment changes. Accordingly, BSEE revised final § 250.734(a)(4) to limit the ROV functions to the critical functions which are now specified in that paragraph, and which is consistent with the definition of critical functions in API Standard 53.

Comments Related to Proposed § 250.734(a)(5)—ROV Crew Training

Summary of comments: A commenter requested that BSEE clarify whether the proposed requirement for maintaining ROVs and having a trained ROV crew on each rig is intended to impose requirements over and above those of the existing requirements of subparts O and S of part 250.

• *Response:* The personnel training requirements of § 250.734(a)(5), which include applicable training requirements for subparts O and S, apply to the ROV crew training required by § 250.734(a)(5). Section 250.734(a)(5) potentially goes go beyond subpart O, however, in that it also requires that personnel authorized to operate an ROV must have a comprehensive knowledge of BOP hardware and control systems. The training provisions for SEMS under § 250.1915 require operators to establish a training program so that all personnel are trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts. This provision sets out specific training requirements for the ROV crew. There are no inconsistencies between § 250.734(a)(5) and subparts O and S. Accordingly, BSEE made no changes to the final rule based on this comment.

Comments Related to Proposed § 250.734(a)(5)—ROV Crew Training

Summary of comments: While several commenters supported the proposed requirements for maintaining an ROV and training the ROV crew, some recommended that training of ROV pilots on stabbing into an ROV intervention panel should not be limited to simulators, as suggested by the proposed rule; real-world, on-the-job training is also valuable. Thus, one commenter also suggested changing ''simulator training'' to ''competence training.''

• *Response:* BSEE agrees with the comment about the value of on-the-job training, but notes that § 250.734(a)(5)'s requirement for simulator training does not preclude other, additional training methods, including on-the-job training; thus, no change to regulatory language is warranted in this regard. Nor did the commenter provide any other reason to replace simulator training with ''competence training.''

Comments Related to Proposed § 250.734(a)(5)—ROV Crew Requirements

Summary of comments: A commenter recommended several revisions to § 250.734(a)(5), including: Changing the proposed requirement that the ROV crew must ''examine all ROV related well-control equipment'' to requiring that the ROV crew ''must be familiar with all ROV related equipment''; revising the requirement that the ''ROV crew must be in communication with designated rig personnel'' to the ''ROV crew must be able to be in constant communication with designated rig personnel''; and changing ''shutting in the well during emergency operations'' to ''carrying out appropriate tasks during emergency operations.''

• *Response:* BSEE agrees with the comment suggesting that the phrase ''shutting in the well during emergency operations'' be changed to ''carrying out appropriate tasks during emergency operations,'' and made that revision in the final rule. This will ensure that the ROV crew is able to conduct many different tasks, instead of just shutting in the well, during emergency operations. The other suggested changes would not substantively change or improve the requirements for ROV crew capabilities.

Comments Related to Proposed § 250.734(a)(6)(iv)—Emergency Functions

Summary of comments: Commenters suggested that the emergency functions requirement in proposed § 250.734(a)(6)(iv) should be operations-specific and not a blanket order to close both casing shear and blind shear rams in all situations. Some commenters recommended using an operational risk assessment to determine the optimum emergency sequence for the specific operation, stating that the sequential shearing requirement is too prescriptive and the prescribed method in the proposed rule may not be the safest approach.

• *Response:* BSEE does not agree that any changes to § 250.734(a)(6)(iv) are needed based on this comment. The only requirement for sequencing in paragraph (a)(6)(v), does not specify any particular sequencing of emergency functions; it only requires a sufficient delay after beginning closure of the lower shear ram before the upper ram begins closure. The specific sequencing of emergency functions should be developed by the operator based on safety considerations.

Summary of comments: One commenter recommended that BSEE remove the requirement that each emergency function must close dual shear rams. The commenter stated that since the sealing shear ram is required to shear the same tubulars as the non-shearing ram, closing both rams in all cases does not provide an advantage. However, another commenter supported the proposed requirement to close a minimum of two shear rams, one of which must seal the well, stating that it will increase the availability of all the emergency BOP functions. Another commenter also supported the proposed requirement and stated that the sequencing will help ensure that at least one of the shear rams will seal.

• *Response:* BSEE disagrees with the comment about removing the requirement that each emergency function must close two shear rams. The autoshear/deadman systems are used as a ''last case'' scenario to operate specific BOP components, are not performed by rig personnel, and are set to activate independently under certain operating criteria. BSEE is requiring both shear rams to close for these emergency functions in order to increase the effectiveness of those emergency BOP systems.

Comments Related to Proposed § 250.734(a)(6)(iv)—Emergency Functions

Summary of comments: Commenters stressed that requiring that each emergency system must always close dual shear rams in sequence will reduce the operating capability of the rigs due to the reduced operating radii induced by such a rule. They stated that the purpose of the EDS is to release the vessel from the well to save lives; if this can be done without polluting, that is a bonus, but the focus is on saving lives first. Commenters asserted that the operations at the time, together with the weather conditions, etc., should dictate what EDS sequence is used, not a prescriptive rule.

• *Response:* BSEE agrees that the primary focus of the EDS, and many other well control systems, is to save lives in addition to preventing environmental harm. The sequencing of the dual shear rams should be set by the operator to function in a reasonable timeframe. If the emergency functions are being activated, then the well-control situation has been analyzed by the rig personnel and the options to control the well have become limited to the emergency functions. These provisions are intended to ensure the safety of the crew and prevent pollution, and therefore require that the emergency functions utilize all of the appropriate components to assist in securing and moving off the well. Thus, no revision to the rule is needed in response to this comment.

Comments Related to Proposed § 250.734(a)(6)(v)—Sufficient Delay

Summary of comments: Commenters requested that BSEE specify the longest period that will be considered ''sufficient delay'' for closing the upper ram, and suggested that ''sufficient delay'' should be the time required to detect the failure of the lower shear ram to hold pressure. The upper shear ram should then be required to close as soon as possible upon the failure to close the lower shear ram.

- *Response:* BSEE does not specify the timing associated with the sequencing in paragraphs (a)(6)(iv) through (vi). The precise sequencing and timeframes for each BOP component to function should be set by the operator based on the specific circumstances (*e.g.,* an operator may choose to use a risk assessment to determine the optimal timeframes).

Comments Related to Proposed § 250.734(a)(6)(vi)—Emergency Control Systems

Summary of comments: A commenter noted that this paragraph would result in additional complexity due to the necessary addition of a timing circuit; this results in less reliability and possibly more failures of the shearing circuit. It also requires more stack mounted accumulators, which are also more likely to fail and render the shear rams inoperable. A commenter suggested that BSEE revise paragraph (a)(6)(vi) by adding, ''[e]mergency disconnect systems are allowed to be activated manually, but once activated must lead to a failsafe state.'' Commenters asked for clarification of the intent of paragraph (a)(6)(vi) and raised concerns about the reference to the ''logic'' of the emergency system potentially preventing the next step in the sequence.

- *Response:* BSEE agrees with the commenter that the control system for the emergency functions should be fail-safe once activated, and has revised final paragraph (a)(6)(vi) by removing the phrase ''and the logic must provide for the subsequent step to be independent from the previous step having to be completed'' and replacing it with the phrase ''once activated.'' This change would allow the systems to be fail-safe without the addition of a timing circuit as suggested by this comment.

Comments Related to Proposed § 250.734(a)(7)—Acoustic Control Systems

Summary of comments: Commenters raised concerns about unintended consequences of this provision, which requires demonstration that an acoustic control system will function in the proposed environment and conditions, asserting that if a failure of the acoustic system results in mandatory repairs for the BOP stack, then operators will be encouraged to reduce the emergency capability of the rig by removing the acoustic system. Commenters recommended that, if operators install an acoustic system, it should be treated as a redundant system allowed under § 250.738(o) or that BSEE should allow the operators to assess the risks of continuing without the acoustic system and act accordingly. A commenter noted that acoustic systems have good potential for secondary, emergency control of the BOP, but that their reliability is not fully established. Thus, according to the commenter, there is a need to conduct a trial of the acoustic systems to evaluate their full potential and BSEE should not penalize the operator if the system fails to perform.

- *Response:* BSEE agrees that the operator should not be penalized if it has already voluntarily decided to install an acoustic system on the rig but does not use the system; however, if the operator chooses to use an acoustic control system, the operator must meet the requirements of § 250.734(a)(7) to demonstrate that the system is functional. Accordingly, BSEE has revised final § 250.734(a)(7) by replacing the word ''install'' with ''use,'' which will clarify that an operator need not demonstrate the functionality of the acoustic system unless the operator uses that system as an additional emergency control measure (in addition to the required autoshear, deadman and EDS systems). In any case, the commenter's concern that a failure to demonstrate the functionality of the acoustic system would result in mandatory repairs to the BOP stack (and thus would encourage removal of the acoustic system) is unfounded; nothing in this provision requires or suggests that the BOP stack would need to be pulled for repairs if that demonstration cannot be made. Additionally, an operator may contact the appropriate District Manager, who can address any questions about the use of an acoustic control system on a case-by-case basis.

Comments Related to Proposed § 250.734(a)(8)—Enable Buttons

Summary of comments: Commenters observed that not all BOP control panels use enable buttons. Many older surface and subsea control systems are manually controlled, which does not permit the use of enable buttons; however, these require two-handed operation of the critical functions. They also noted that API Standard 53 addresses two-handed operation, but not enable buttons. The commenter recommended that BSEE remove the proposed requirement for enable buttons from this section or add references to the relevant provisions in API Standard 53.

- *Response:* BSEE agrees with the comment that there are other options, besides enable buttons, to ensure two-handed operation for critical functions on the control panels. Accordingly, BSEE has revised final § 250.734(a)(8) to state that ''[y]ou must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.'' This change would provide the flexibility to allow for other options besides enable buttons.

Comments Related to Proposed § 250.734(a)(11)(ii)—Critical BOP Equipment

Summary of comments: Commenters recommended that BSEE revise this proposed provision to clarify the meaning of ''critical BOP equipment'' consistent with API Standard 53. The commenters also noted that the term ''competent person'' is defined in API Standard 53 as: ''person with characteristics or abilities gained through training, experience, or both, as measured against the manufacturer's or equipment owner's established requirements.'' These commenters also recommended changing the language in proposed paragraph (a)(11)(ii), requiring a ''comprehensive knowledge of BOP hardware and control systems,'' to ''a knowledge of BOP hardware and control systems commensurate with their responsibilities.'' A commenter also suggested that established guidelines are needed for measuring comprehensive knowledge of BOP hardware and control systems, and that additional time beyond the proposed 90 days for compliance is needed if testing or certain training classes are required. Another commenter advocated that BSEE require the equipment owner to establish minimum requirements for personnel authorized to operate critical BOP equipment.

- *Response:* BSEE does not agree that any changes to this paragraph are appropriate based on the comments. Section 250.734(a)(11) is essentially a performance-based requirement, and several of the changes suggested by commenters would unnecessarily confine operators in deciding how best to meet the goals established by this provision. Thus, BSEE has decided not to define the term ''critical BOP equipment;'' however, the discussions of critical BOP equipment in API Standard 53 could be used by an operator as a guide to understanding the scope of critical equipment.

Similarly, BSEE does not agree that the other suggested changes to paragraph (a)(11)(ii) are appropriate because such changes could unnecessarily limit the scope of the required personnel knowledge. BSEE does not expect that the ''comprehensive knowledge'' required by § 250.734(a)(11)(ii) would necessarily include knowledge of BOP hardware and control systems that are so far outside the scope of an individual's current or potential responsibilities that there is no reasonable possibility that the individual would ever be called on to operate such equipment; however, BSEE believes it is important that all personnel operating critical BOP equipment understand how their specific responsibilities fit within the BOP system as a whole. Overly narrow understanding of the whole system, including hardware and controls, could result in personnel not understanding the importance of their own duties to the success of the system in preventing a blowout.

BSEE also does not agree that the compliance timeframe for this paragraph should be changed. Commenters provided no factual basis for such a change. In addition, BSEE expects BOP operating personnel to be familiar with their responsibilities and to be trained in accordance with the applicable requirements of 30 CFR part 250, subparts O and S (*e.g.,* 250.1503(a)). Ensuring the competency of rig personnel to perform their assigned duties is also consistent with current industry standards (*see, e.g.,* API RP 75).

BSEE also does not agree with the suggestion that the responsibility for compliance with § 250.734(a)(11) should be transferred from the facility operator to some ''equipment owner'' who may not be familiar with the specific circumstances under which the BOP equipment will be used.

Comments Related to Proposed § 250.734(a)(12)—Riser Fluid Displacement

Summary of comments: Commenters noted that the proposed requirement that fluid in the riser be displaced with seawater before the riser is removed did not include an exception for emergency or unplanned LMRP disconnects in which the fluid in the riser would not be displaced. Commenters suggested displacing the riser fluid using a closed volumetric visual control systems to observe fluid gains and losses.

- *Response:* BSEE is not revising paragraph (a)(12). BSEE expects that operators will plan for riser displacement as appropriate and based on safety factors. BSEE expects the operator to take whatever appropriate action is needed in an emergency situation to ensure safety of workers and protection of the environment.

Comments Related to Proposed § 250.734(a)(13)—Well Cellars

Summary of comments: Commenters requested clarification of the proposed requirement to install a BOP stack in a well cellar when in an ice scour area. The commenters seek to ensure that this would only require that the well cellar be deep enough to ensure that the lower BOP stack—but not the lower stack and LMRP—is enclosed. Another commenter observed that this proposed requirement is addressed in, and would conflict with, the proposed Arctic OCS rule; thus, it should be removed from this rulemaking.

- *Response:* BSEE has not made any changes to § 250.734(a)(13). The commenter did not specify how this provision conflicts with the proposed Arctic OCS rule. It is BSEE's expectation that the top of the BOP stack (not including the LMRP) must be set below the deepest possible ice scour depth. The LMRP can be disconnected from the BOP stack and would be removed if the rig has to move off location, leaving just the BOP stack in place.

Comments Related to Proposed § 250.734(a)(14)(iii)—Fail-Safe Valves and Side Outlets

Summary of comments: Commenters recommended adding to the proposed provision in paragraph (a)(14)(iii)—regarding valves used in side outlets for choke lines and kill lines—that the valves must be fail-safe. Another commenter recommended revising paragraph (a)(14)(iv) to require installation of the side outlet below the lowest sealing shear ram instead of below each sealing shear ram.

- *Response:* No changes to § 250.734(a)(14)(iii) are necessary regarding the valves being fail-safe. BSEE understands that these valves are already fail-safe closed. However, BSEE agrees with the comment about paragraph § 250.734(a)(14)(iv) and has revised final paragraph (a)(14)(iv) by replacing ''each'' sealing ram with ''the lowest'' sealing ram to allow more flexibility for component placement.

Comments Related to Proposed § 250.734(a)(15)—Gas Bleed Line

Summary of comments: Regarding the proposed requirement to install a gas bleed line with valves for the annular preventer, commenters noted that many existing annular BOPs do not have a side outlet. They asserted that every valve and every outlet added to the BOP systems increases potential leak paths and reliability concerns. A commenter proposed that, if BSEE did not remove this section, it should be re-worded to pertain only to the uppermost annular preventer.

Another commenter emphasized that, because the upper annular is traditionally the working annular, the bleed valves are typically installed below the upper annular. Other commenters asserted that adding another set of gas bleed valves under the lower annular would require additional pilot lines and valves per pod, and that spare pilot lines and valves are limited and may be needed for higher priority pipe ram or shear ram functions. This commenter requested that BSEE clarify the technical reason for adding a set of gas bleed valves under the lower annular in this situation.

Commenters also requested additional time to install the gas bleed line and valves. Commenters asserted that the lead times for engineering, component procurement and installation of an additional valve for gas relief under the lower annular would preclude compliance with the rule within 90 days.

- *Response:* BSEE agrees with several of these comments, and has revised final § 250.734(a)(15) to clarify that if a subsea BOP has dual annulars, the gas bleed line must be installed below the upper annular. BSEE has also removed the proposed requirement to install gas bleed lines on each annular. These revisions should eliminate or minimize commenters' concerns about space issues, reliability, and addition of possible failure points. BSEE also agrees that it will take more than the proposed 90 days to install the required gas bleed lines and valves, and revised the compliance date for paragraph (a)(15) to 2 years after publication of the final rule. Extending the compliance date will provide adequate time for installation of the gas bleed line and valves while avoiding any rig downtime.

Comments Related to Proposed § 250.734(a)(16)—BOP System Capabilities

Summary of comments: Commenters criticized the prescriptive language in proposed § 250.734(a)(16)(i) through (iii), and questioned whether the intent is to require that shear rams must be able to sever the pipe, and seal the pipe, regardless of where the pipe is within the bore. The commenters said that if this is what BSEE wants to achieve, then the regulation should state that.

Commenters also asked why, if the pipe does not need to be centralized to shear it, require centralization of the pipe? Commenters noted that not all OEMs require a mechanism for centering tubulars, and that centralization can be achieved via the geometry of the blade design.

A commenter suggested that the proposed text steers technology development in a specific direction which may inhibit development of other technologies. On the other hand, another commenter stated that BSEE explicitly notes that this requirement is designed to encourage further technological development, driving safety improvements beyond current industry practice.

- *Response:* No changes to § 250.734(a)(16) are necessary based on these comments. BSEE understands that some rams may be capable of shearing on the rams' cutting edges, without centralizing the pipe. However, it is safer to have the pipe centered while shearing in order to optimize shearing capabilities and reduce risk by ensuring that the pipe to be sheared is across the shearing surfaces. It is not BSEE's intention to inhibit applicable technological advancements, however; in fact, BSEE believes this performance-based requirement will encourage development and use of technology to center the pipe while shearing. Moreover, nothing in this requirement expressly or implicitly discourages development of other new technologies to improve shearing capabilities and decrease risk. Any operator that wishes to do so, may seek approval from the District Manager or Regional Supervisor under § 250.141 for use of any alternative equipment or procedures that are at least as protective as this requirement.

Comments Related to Proposed § 250.734(a)(16)(ii)—Ability To Mitigate Compression

Summary of comments: A commenter asserted that the proposed requirement that the subsea BOP have the ''ability to mitigate compression'' of the pipe stub is too vague. The commenter asserted that the critical factor is the ability of the BOP to accept the pipe stub and suggested that BSEE revise the rule to reflect that.

- *Response:* BSEE has not made any changes to § 250.734(a)(16)(ii) based on the comment. Mitigating the compression of the pipe stub would allow for the pipe stub to be accepted between the shear rams and would not interfere with the shearing functions.

Comments Related to Proposed § 250.734(a)(16)(iii)—Batteries

Summary of comments: Commenters suggested revising this paragraph to require ''subsea control system batteries'' instead of ''subsea electronic module batteries in the BOP control pods,'' noting that there are other batteries used in BOP equipment (*e.g.,* an acoustic pod, a deadman system).

- *Response:* BSEE has not made any changes to § 250.734(a)(16)(iii) based on the comment. BSEE understands that the subsea electronic module is an important component to ensure operability of the subsea BOP. However, the commenter did not provide any support for its requested change, and BSEE currently lacks enough information to justify such a change.

Comments Related to Proposed § 250.734(b)(1)—BAVOs

Summary of comments: Commenters observed that, since this section requires a verification report from a BAVO ''documenting the repairs to the BOP and that the BOP is fit for service,'' it cannot be implemented until BSEE approves a suitable number of organizations to serve as BAVOs.

Commenters also asserted that the operator should have primary responsibility for certifying the required documentation, and that the BAVO should support such certification by verifying the information provided by the operator. Other commenters recommended changing the requirement to use a BAVO to a requirement to use an ''independent third-party.''

- *Response:* As previously discussed, BSEE has revised the compliance date for the use of a BAVO to one year after BSEE publishes a list of BAVOs. Part III of this document provides a more detailed discussion of this compliance date.

In addition, as previously discussed, this and the other BAVO-related provisions do not eliminate or transfer the operator's regulatory responsibilities to the BAVO; the operator is responsible for ensuring compliance with § 250.734(b). As explained earlier in this document, BSEE has decided that it is necessary that BSEE review and determine the qualifications of organizations that will perform this verification function.

Comments Related to Proposed § 250.734(b)(2)—BOP Testing

Summary of comments: Regarding the proposed requirement to re-test the BOP, including the deadman or lower stack ROV intervention functions, upon relatch after subsea BOP repairs, a number of commenters stressed that when the LMRP is retrieved, it is not necessary to re-test those functions. They asserted that the deadman and ROV systems were tested on the surface and subsea upon initial installation and that, after repair, if the systems are tested on the surface before redeployment, a re-test after re-latching should not be required. They also stated that API Standard 53 does not specify re-testing under such circumstances. The commenters stated that subsea testing of the deadman system with a dynamically-positioned rig is a high consequence operation, and the more times the test is performed, the higher the probability a station-keeping incident will occur. They also stated that these tests would lead to additional unnecessary wear on blind shear rams and reduction of overall system reliability.

Some commenters agreed, however, that if any part of the deadman or ROV systems is dismantled, repaired, or affected as part of the BOP repair, then it would be prudent to verify functionality of these systems upon re-latching. Commenters recommended that BSEE revise this section to change re-testing of the deadman and ROV intervention functions to re-testing of any functions affected during the repair.

- *Response:* BSEE intends that, if the BOP stack is pulled for repair to any part of the BOP system, testing must be completed before resuming operations. However, BSEE agrees with several of the points made by the comments; thus, BSEE has revised final § 250.734(b)(2) to state that, upon relatch of the BOP, an operator must perform an initial subsea BOP test in accordance with § 250.737(d)(4), including testing the deadman. If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737. These revisions will effectively limit the scope of the re-testing requirement—and therefore the potential negative consequences from excessive wear caused by re-testing—by requiring comprehensive re-testing of all BOP components, including ROV functions, only when repairs exceed 30 days. For all repairs lasting 30 days or less, this revised provision would require less extensive re-testing; for example, re-testing under this situation would not need to cover all ROV intervention functions and would require retesting of only one set of rams (instead of all rams).

In addition, the commenters' concern about the possibility that re-testing would increase the probability of a dynamically-positioned rig going off-station is minimized by the fact (as discussed later in this document with regard to proposed § 250.737(d)(13)) that many rigs already have updated BOP control systems that allow power to other systems, including dynamic positioning systems, to remain on during deadman testing.

What associated systems and related equipment must all BOP systems include? (§ 250.735)

As provided for in the proposed rule, this section combines and revises provisions from several sections of the existing regulations and consolidates system and equipment requirements applicable to all BOPs. Those requirements cover accumulator systems, control station locations, choke and kill line installation, and remotely-operated locking devices for sealing rams on surface BOPs (except pipe or variable bore rams that already have non-hydraulically operated locks). BSEE has revised certain provisions of proposed § 250.735 in the final rule as discussed in the comment responses for this section and in parts V.B.2 and V.C of this document.

Comments Related to Proposed § 250.735(a)—Surface Accumulator System

Summary of comments: Multiple commenters suggested that the accumulator system volume capacity requirements of proposed § 250.735(a) contradict the analogous provisions of API Standard 53 and API Spec. 16D, that the proposed capacity requirements are not achievable, and that the proposed language is so ambiguous that operators could not understand the rule's intent. Multiple commenters stated that the proposed requirement that surface accumulators must provide 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP (the 1.5 times volume capacity requirement) could effectively force the elimination of some BOP components from existing BOP systems, and thus either reduce the number of redundant controls or require operators to install additional equipment.

Several commenters asserted that the proposed requirements would increase the number of accumulator bottles needed, would require upgraded accumulator system controls, and would significantly increase costs. Also, the commenters asserted that the extra weight from additional bottles, given limited deck space availability, could cause structural issues with the rig. Further, the commenters asserted that this additional equipment would require additional maintenance and potentially render the systems less reliable. For certain older rigs, the commenters stated that the additional requirements could force the removal of the rigs from service.

For such reasons, multiple commenters recommended deleting the proposed 1.5 times volume capacity requirement and requiring instead that surface accumulator sizing meet the specifications of API Standard 53 or API Spec. 16D (since the methods discussed in API Spec. 16D are also included in API Standard 53).

- *Response:* BSEE agrees with several of the commenters' concerns. BSEE has decided to revise final § 250.735(a) by deleting the 1.5 times volume capacity requirement for all surface accumulators and instead requiring that all accumulator systems (including those servicing subsea BOPs) meet the sizing specifications of API Standard 53. This revision will not degrade safety or environmental protection compared to the proposed requirement. BSEE has determined that the methods for calculating the necessary fluid volumes and pressures in API Standard 53 provide an acceptable amount of usable fluid and pressure to operate the required components, while still ensuring—as required by § 250.735(a)—that accumulators have enough charge to remain at least 200 psi above the pre-charge pressure, without recharging, even after operating all BOP functions. This provides a sufficient margin of error to prevent any safety or environmental harm from failure of pressure to the BOP and is also consistent with API Standard 53.

Comments Related to Proposed § 250.735(a)—API Standard 53

Summary of comments: Some comments stated that § 250.735(a) is inconsistent with API Standard 53 in other ways; for example, API Standard 53 does not require accumulator regulators on subsea BOP stacks to be supplied by rig air.

- *Response:* This regulation does not require that subsea accumulators be supplied by rig air. It merely imposes certain requirements ''if'' subsea accumulators are supplied by rig air. BSEE understands that rig air is used for surface accumulators and not subsea. In addition, as discussed elsewhere in this document, BSEE has made several revisions to final § 250.735(a) to align the rule more closely with API Standard 53.

Comments Related to Proposed § 250.735(a)—Surface Accumulator System

Summary of comments: Multiple commenters expressed concern with the requirement in proposed § 250.735(a) that the accumulator system be able to supply pressure to operate all BOP functions, and to shear pipe as the last step in the BOP sequence, without assistance from a charging unit. They asserted that this provision would increase the number of accumulator bottles needed and would require upgraded accumulator system controls and that costs associated with the additional bottles would be significant. The commenters also stated that the extra weight from additional bottles, given limited deck space availability, could cause structural issues with the rig.

- *Response:* BSEE agrees with the commenters' concerns about the proposed requirement that the accumulator system be able to operate all BOP functions, with the blind shear ram being last in the sequence, and still have enough pressure to shear pipe and seal the well. Accordingly, BSEE has revised § 250.735(a) by replacing ''all BOP functions'' with ''the BOP functions as defined in API Standard 53.'' Revising the BOP functions in response to the comments to align with API Standard 53, in conjunction with the revisions to the fluid capacity volume requirements previously discussed, will eliminate or significantly reduce the commenters' concerns about the costs associated with the additional bottles. In particular, because the final rule requires that the accumulator bottles be able to operate the BOP functions as defined by API Standard 53, fewer accumulator bottles should be needed (as compared to the proposed requirement), as the commenters indicated. This, in turn, will minimize (as compared to the proposed rule) the potential impacts on the rig structure that could have resulted from the extra weight of additional bottles as well as the potential impacts on operations and safety from storage of the bottles in the limited deck space available.

For the same reasons, BSEE has also removed the phrases ''with the blind shear ram being the last in the sequence'' and ''enough pressure to shear pipe and seal the well with . . .'' from final § 250.735(a). Removing these phrases will eliminate the impression that the proposed language would have mandated that the blind shear ram be the last step in the BOP sequence. In addition, BSEE agrees that the proposed language regarding sequencing of the blind shear ram is not necessary, as long as the accumulator is able to provide sufficient volume to operate all the required BOP functions under MASP.

Comments Related to Proposed § 250.735(a)—Surface Accumulator System

Summary of comments: A commenter recommended changing ''surface accumulator system'' to ''main accumulator system.'' The commenter asserts that this will ensure that other surface accumulators (*e.g.*, for the diverter system) are not included and will allow for subsea accumulators that are used by the main control system (*e.g.*, LMRP mounted) to be included on subsea stacks.

• *Response:* BSEE agrees that proposed § 250.735(a) could have resulted in confusion about the types of accumulator systems to which the requirements applied. Accordingly, BSEE has revised final § 250.735(a) by replacing ''surface accumulator system'' with ''[a]n accumulator system (as specified in API Standard 53).'' This revision will help clarify that the accumulator system requirements of paragraph (a) are applicable to either a surface or subsea BOP system (as discussed in API Standard 53).

Comments Related to Proposed § 250.735(b)—Automatic Backup to the Primary Accumulator Charging System

Summary of comments: Commenters stated that this proposed paragraph—which would require ''an automatic backup to the primary accumulator-charging system''—was unclear. They requested clarification on the meaning of the phrase ''automatic backup to the primary accumulator charging system.'' They asked BSEE to answer several questions about the meaning of this phrase in several specific factual situations; *e.g.*, whether, assuming a charging system is an electric-driven pump, the automatic backup requirement would apply if the electric-driven pump is also capable of being powered from the emergency bus instead of the primary power generation from the rig.

Commenters also claimed that, if the proposed requirement for an automatic power source is intended to require a second complete pumping unit, the time needed to procure and install such equipment would preclude compliance within the proposed 90 days. Other commenters recommended that BSEE delete paragraph (b) altogether and instead simply reference API Standard 53 and API Spec. 16D.

• *Response:* No changes to the requirements for an automatic backup to the primary accumulator charging system in § 250.735(b) are necessary. In fact, the requirements in § 250.735(b) have been in place—in former § 250.443(a)—for years, and BSEE is not aware of any problems occurring because of confusion about the automatic backup to the primary accumulator charging system. Nor is it necessary to incorporate API Spec. 16D into paragraph (b). This regulation requires minimum capabilities, and if compliance with API Spec. 16D or other industry standards meets these minimum requirements, there is no reason why an operator could not follow that standard.

Comments Related to Proposed § 250.735(e)—Kill Line

Summary of comments: Multiple commenters stated that the placement of the term ''kill line'' in proposed § 250.735(e) was confusing and recommended that BSEE refer to the language in API Standard 53 instead.

• *Response:* BSEE agrees that proposed § 250.735(e) was not clear. Accordingly, BSEE has revised § 250.735(e) to clarify that the kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram. This clarification will avoid confusion related to the fact that many BOP stacks use a test ram (which is not a well-control ram) in the bottom-most part of the BOP.

Comments Related to Proposed § 250.735(g)—Hydraulically Operated Locking Devices

Summary of comments: Multiple commenters urged that this provision—regarding hydraulically operated locks installed on BOPs with sealing rams (*i.e.*, pipe rams/VBRs or blind shear rams)—distinguish between surface and subsea BOP stacks. Some commenters noted that locking devices for ram-type BOPs are already addressed in § 250.733(e). Some commenters indicated that surface stacks can use manual locks, while subsea BOP stacks should use hydraulic locks. Other commenters observed that since most surface stacks do not use hydraulic rams, installation of hydraulic locks in compliance with this provision would require 3 years from publication of the final rule, while other commenters stated that the proposed requirement (and proposed § 250.733(e)) would be unduly costly. One commenter recommended that BSEE replace the proposed requirement for hydraulic locks with a requirement for remotely-operated locks.

• *Response:* BSEE agrees with several of the observations made by the commenters. In particular, BSEE agrees that the purpose of the proposed rule—to ensure that sealing rams on surface BOPs, as well as subsea BOPs, can be locked promptly and with minimal risk to rig personnel—can be effectively achieved with various kinds of locking devices appropriate to each type of BOP (surface or subsea) and to each type of sealing ram. For subsea BOP sealing rams, hydraulic locks will continue to be appropriate, since those rams are already required to be hydraulically operated (under both former § 250.442(a) and new § 250.734(a)(1)) and since existing locking devices for those rams are also hydraulically operated.

For surface BOPs, however, other locking devices can achieve the same purpose as hydraulic locks with no incremental loss of personnel safety or environmental protection. As suggested by one of the commenters, other types of remotely-controlled locks could also ensure that sealing rams can be locked without exposing rig personnel to unnecessary risk. BSEE has determined that any remotely-controlled lock (whether or not hydraulically operated) is appropriate for blind shear rams on surface BOPs. This requirement will help prevent potential blowouts and reduce the risk of personnel having to be in or near a potentially hazardous area during an emergency event by making it unnecessary for them to manually operate manual locks.

By contrast, pipe rams and VBRs on surface BOPs can be safely and effectively locked manually, as they have been under former § 250.443(f), or remotely. BSEE is not aware of any well-control incident that was directly related to failure of a surface BOP manual lock; nor is BSEE aware of any personnel safety incident resulting from operation of a manual lock on pipe rams or VBRs. Thus, given the past effectiveness of manual locks, BSEE has determined that it is not necessary at this time to require hydraulic or other remotely-controlled locks on surface BOP pipe rams/VBRs.

Accordingly, BSEE has revised final § 250.735(g) to distinguish between surface and subsea BOPs, and to provide operators with more flexibility in their choice of locking mechanisms for sealing rams on surface BOPs. Specifically, the final rule will require hydraulic locks for all subsea BOP sealing rams, remotely-operated locks for surface BOP blind shear rams, and manual or remotely-controlled locks on surface BOP pipe rams/VBRs.

In addition, BSEE understands that the requirement to install remotely-controlled locks (whether or not hydraulically operated) on surface BOP blind shear rams would take significantly more time than 90 days from publication of the final rule, due to the need to procure enough of the necessary equipment as well as to practical and logistical problems with installation. For example, as implied by the commenters, installation of hydraulic locks on BOP surface stacks that do not have hydraulic rams would take substantially more time because hydraulic systems to control the locks in those cases will also need to be added to the BOP stack. BSEE also agrees that failure to install hydraulic or other remotely-controlled locks by the proposed compliance date could result in significant rig downtime. Accordingly, BSEE has determined that 3 years after publication of the final rule is an appropriate timeframe for acquiring and installing all of the necessary systems and equipment to meet the requirement for surface BOP blind shear rams, and has revised the compliance date in final § 250.735(g)(2) accordingly.

What are the requirements for choke manifolds, kelly-type valves, inside BOPs, and drill string safety valves? (§ 250.736)

As provided for in the proposed rule, this section reflects a combination of provisions from several sections of the existing regulations that established technical requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves. This final rule makes several revisions to the former requirements with respect to choke manifolds and kelly-type valves. BSEE has revised certain provisions of proposed § 250.736 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed §§ 250.736(a) Through (c)—API Standard 53

Summary of comments: A commenter recommended that BSEE revise proposed § 250.736(a) to rely on API Standard 53 for the design and operation of the choke manifold. The commenter also suggested that BSEE delete proposed paragraphs (b) and (c) because the matters they cover would already be covered by the reference to API Standard 53 in paragraph (a).

Another commenter asked whether it was BSEE's intent, in proposed § 250.736(b), that all choke manifold components, including valves downstream of the chokes, be rated for the full working pressure of the BOP stack.

- *Response:* BSEE disagrees with the recommended revisions to § 250.736(a) through (c). These paragraphs describe general requirements for the choke manifold. Nearly identical requirements have been in place for many years (formerly in § 250.444), and BSEE is not aware of industry raising any prior concerns with implementing those longstanding requirements. With regard to paragraph (b), the need to ensure that all choke manifold components are able to withstand the wellbore pressures that they will encounter is as important under this final rule as it was under the existing regulation. Nonetheless, if an operator has any questions about the meaning of this longstanding requirement, it can ask the District Manager for assistance.

Comments Related to Proposed § 250.736(d)—Kelly Valves

Summary of comments: Commenters recommended that BSEE revise this paragraph to clarify that it only applies to rigs that operate with kelly valves. One commenter asserted that proposed § 250.736(d)(1) requires the use, "during all operations," of "a kelly valve installed below the swivel" even though kelly valves are no longer in widespread use in offshore drilling operations. Similar comments claimed that kelly valves are seldom used and have limited applications in OCS operations because almost every rig on the OCS now uses drill pipe instead of kelly valves. For that reason, one commenter recommended that BSEE delete proposed paragraphs (d)(2) and (3), since these provisions are obsolete. Similarly, some commenters asserted that the methodology required in proposed paragraph (d)(3) has been rendered obsolete by the proven use and operation of top drives.

- *Response:* BSEE agrees with the comments about the limited application of kelly valves and has revised final § 250.736(d)(1) by replacing the references to kelly valves with the phrase "applicable [k]elly-type valves as described in API Standard 53." For the same reason, BSEE has deleted paragraphs (d)(2) and (3) from final § 250.736. BSEE has determined that the reference to API Standard 53 specifications for kelly-type valves in paragraph (d)(1) renders paragraphs (d)(2) and (3) unnecessary.

Comments Related to Proposed § 250.736(d)(4)—Top-Drive Systems

Summary of comments: Commenters stated that proposed paragraph (d)(4)—requiring a strippable kelly-type valve on a top-drive system with a remote-controlled valve—is more specific than API Standard 53, and that BSEE should simply reference API Standard 53.

- *Response:* BSEE disagrees with the comments suggesting changes to § 250.736(d)(4). This provision has been in the existing regulations for many years (*i.e.,* in former § 250.445(d)) and BSEE does not believe that incorporating API Standard 53 would improve safety or environmental protection as compared to the former regulations and this final rule. In addition, BSEE is unaware of prior industry concerns associated with the equipment required by this longstanding requirement. Thus, there is no need to add the reference to API Standard 53 suggested by the commenter.

What are the BOP system testing requirements? (§ 250.737)

As provided for in the proposed rule, this section combines and revises various BOP testing requirements from the existing regulations. Paragraph (a) reorganizes and consolidates the pressure testing frequency requirements for drilling, workovers, completions, and decommissioning. Paragraph (b) requires certain pressure test procedures while paragraph (c) clarifies the duration of the pressure tests. Paragraph (d) further clarifies testing procedures for various situations and equipment (*e.g.,* stump testing, initial subsea testing, ram and annular testing). BSEE has revised certain provisions of proposed § 250.737 in the final rule as discussed in the comment responses for this section and in parts V.B.6 and V.C of this document.

Comments Related to Proposed § 250.737(a)(1)—Installation BOP Test

Summary of comments: A commenter requested clarification that proposed § 250.737(a)(1) only requires a full BOP pressure test upon an initial installation, not subsequent installations following repairs or unplanned pulls. The commenter mentioned that studies have demonstrated that most faults are discovered during function testing; based on these findings, function testing is more valuable than pressure testing in measuring operability of the system.

- *Response:* The language requiring a pressure test when a BOP is installed is the same as the longstanding language in former § 250.447(a) and requires no clarification at this time. There is no change in the meaning or intent of that requirement, now located in § 250.737(a)(1). In addition, BSEE is aware that BOP failures during pressure testing happen, and therefore it is important to pressure test to help verify the integrity of the BOP system to ensure it can function as intended.

Comments Related to Proposed § 250.737(a)(2)—14-Day BOP Pressure Test

Summary of comments: BSEE received a number of comments on the proposed requirement in § 250.737(a)(2) that BOP pressure tests be conducted before 14-days have elapsed since the prior test, and no later than 30 days after since the last blind shear ram BOP pressure test. One commenter supported more frequent BOP pressure tests of 7 days for all BOPs used in Arctic OCS operations. However, other commenters supported less frequent BOP pressure testing. Commenters cited the provisions of API Standard 53, which recommends a 21-day BOP test cycle for shear ram BOPs, as well as international industry best practices, in support of longer pressure test intervals. Multiple commenters pointed out that less frequent testing would mitigate wear and tear on the equipment from the testing itself, and wear and tear adversely affects long-term reliability of the equipment and thus increases the risks from equipment failure.

• *Response:* BSEE has not made any changes from the 14-day testing requirement in the proposed and existing regulations. BSEE did not receive any new supporting data with any comments that would support changes to the existing 14-day testing interval at this time. Although BSEE is aware of concerns that the more frequently BOPs are tested, the more likely the equipment is to wear out prematurely, and thus to fail to operate properly when needed, further study, research, and discussions with subject matter experts is needed for BSEE to make a determination that it is appropriate to change the general 14-day testing requirement. An operator that believes a different interval is warranted by special circumstances, however, may seek approval from the District Manager or Regional Supervisor to use an alternative procedure in accordance with § 250.141. More details concerning this issue are contained in part V.B.6 of this document.

Comments Related to Proposed § 250.737(a)(4)—District Manager Directed BOP Pressure Test

Summary of comments: BSEE received one comment on proposed paragraph (a)(4), objecting to the BSEE District Manager having the authority to increase BOP testing frequency.

• *Response:* Like similar provisions throughout 30 CFR part 250, § 250.737(a)(4) is intended to give District Managers the necessary flexibility and discretion to require actions as needed in specific cases to fulfill the purposes of the regulation, and BSEE is therefore not making any changes to proposed paragraph (a)(4). In any case, this provision is identical to the longstanding language in the current regulations (*i.e.,* former § 250.447(b)), and BSEE is unaware of any significant concerns raised by operators in connection with District Managers exercising this authority.

Comments Related to Proposed § 250.737(b)—BOP Pressure Test Procedures

Summary of comments: Another commenter recommended that BSEE require an additional ram low pressure test after the completion of the high pressure test. The recommended ram testing sequence would be, in this case, low pressure, high pressure, and low pressure. The commenter stated that it is possible to tear the packing element elastomer seal during high pressure test such that it might not seal again during a low pressure test.

• *Response:* The pressure test procedures reflected in the rule have been in place for many years (formerly in § 250.448), and BSEE is not aware of issues created by, or operators raising any concerns with, those procedures. BSEE is also unaware of any new data supporting a change in the procedures and is therefore not revising § 250.737(b) as suggested.

Comments Related to Proposed § 250.737(b)(2)—BOP High Pressure Test

Summary of comments: Commenters noted that this provision does not differentiate between initial and subsequent testing, noting that proposed § 250.737(d) requirements for subsea BOPs differentiate between stump, initial and subsequent testing, all of which utilize different test pressures. Another commenter asked BSEE to clarify proposed paragraph (b)(2) to confirm that the blind shear rams will only be tested to the high-pressure for the well at initial installation, and that subsequent tests will be performed to the casing test pressure.

• *Response:* BSEE has not made changes to proposed § 250.737(b)(2), which is largely based on the longstanding requirements for BOP testing in the current rules (former § 250.448(b)), including blind shear ram testing. BSEE does not agree that the clarification requested by the commenter is necessary. BSEE discusses the additional testing requirements for subsea BOPs in more detail later in response to comments on proposed § 250.737(d). If an operator has any questions about testing specific components, it may contact the appropriate District Manager for guidance.

Comments Related to Proposed § 250.737(b)(3)—Annular BOP High Pressure Test

Summary of comments: A commenter suggested that the words ''lesser of the'' are missing from this paragraph, noting that hydrostatic pressure should also be accounted for in subsea tests by deducting that pressure from the surface applied pressure.

• Response BSEE has not made any changes to § 250.737(b)(3). That provision allows the operator to choose between 70 percent of the RWP or 500 psi greater than the calculated MASP for its high pressure test. The operator is free to use the lesser of those pressures if it so chooses, and no changes to the regulatory language are required to allow that. In addition, the hydrostatic pressure is already accounted for in the subsea BOP test, because it is added to the applied surface pressure to equal the MASP at the mudline.

Comments Related to Proposed § 250.737(b)(3)—Annular BOP High Pressure Test

Summary of comments: Another commenter recommended that the pressure test on the annular should be to a minimum of 70 percent of the RWP, stating that at times the annular is tested in excess of 70 percent of the working pressure, while not exceeding the RWP.

• *Response:* BSEE has not made any changes to § 250.737(b)(3). That provision requires testing to either 70 percent of the RWP or 500 psi greater than the MASP. However, if an operator believes there are situations where testing to higher than 70 percent of the RWP is prudent and no less protective than this regulatory requirement, it may seek approval for alternative test pressures from the appropriate District Manager under § 250.141.

Comments Related to Proposed § 250.737(c)—BOP Pressure Test Duration

Summary of comments: Commenters suggested that pressure testing regimes are clearly defined in API Standard 53, and that BSEE should align the rule with API Standard 53 or at least reference that standard. A commenter also suggested that BSEE remove the use of predictive-type technology from the rule. A commenter also suggested that BSEE follow API Spec. 6A guidance on pressure stabilization.

- *Response:* BSEE has not made any changes to § 250.737(c), which is identical in most respects to longstanding requirements in the existing regulations (formerly § 250.448(c)). The comment does not identify or explain the type of predictive-type technology to which it objects; however, if it refers to the use of charts or digital recorders, BSEE notes that the existing regulations also refer to charts and recorders. BSEE is unaware of any concerns regarding conflicts with API Standard 53 or Spec. 6A for pressure testing durations or pressure stabilization. If there are any concerns surrounding the duration and method of pressure testing, operators may contact the appropriate District Manager for guidance.

Comments Related to Proposed § 250.737(c)—BOP Pressure Test Duration

Summary of comments: Other commenters noted that proposed § 250.737(c) will result in a large number of new chart recorders being ordered concurrently by industry, and that lead times for new equipment may exceed the proposed 90 days for compliance and put rigs out of compliance. These commenters requested 12 months to obtain and install the necessary equipment across all rigs.

- *Response:* BSEE has not made any changes to the compliance date for this provision. If an operator has any specific concerns about availability of equipment to meet the compliance date, it may contact the District Manager for guidance or request approval to use alternative technology or procedures under § 250.141.

Comments Related to Proposed § 250.737(d)(2)—Surface BOP Test With Water

Summary of comments: Commenters expressed concerns about the proposed requirement to use water to test a surface BOP system. Commenters agreed that water should be used for the initial test of a surface BOP, but asserted that after the initial test, the use of mud is acceptable. Commenters suggested that BSEE revise the final rule to allow the operator to select test fluid appropriate for the well conditions.

- *Response:* BSEE agrees with the comments about initially testing surface BOPs with water, then allowing other appropriate fluids to be used for subsequent testing. Accordingly, BSEE has revised final § 250.737(d)(2) by clarifying that water must be used for the initial test of a surface BOP system, but that subsequent tests may use drilling, completion, or workover fluids. The revised requirement would address the comments raised about the use of water for post-initial testing while still preserving well integrity by not reducing the hydrostatic column.

Comments Related to Proposed § 250.737(d)(2)(ii)—72-Hour Surface BOP System Test Notification

Summary of comments: A commenter also suggested that the initial test of surface BOPs should be the only applicable test requiring 72-hour notice to BSEE; subsequent testing must comply with the test frequency required by the rules, so notification to BSEE of subsequent tests should not be required.

- *Response:* BSEE agrees with the comment and has revised final § 250.737(d)(2)(ii) by clarifying BSEE's intent that the notice requirements for this paragraph apply only to the initial test.

Comments Related to Proposed § 250.737(d)(3)(iii)—72-Hour Stump Test Notification

Summary of comments: Multiple commenters recommended deleting § 250.737(d)(3)(iii), which requires the operator to notify the BSEE District Manager at least 72 hours before the stump test so BSEE representative(s) can witness the testing.

- *Response:* BSEE has not made any changes to § 250.737(d)(3)(iii). BSEE requires notification to help ensure compliance with the approved permits.

Comments Related to Proposed § 250.737(d)(3)(iv)—BOP Stump Test ROV Functions

Summary of comments: Two commenters recommended adding more specific details to paragraph (d)(3)(iv), which requires testing and verification of all ROV intervention functions on subsea BOP stacks during stump testing. The commenters suggested replacing ''all ROV . . . function'' with specific functions (*i.e.,* the shear ram close, one pipe ram close, and the LMPR unlock/unlatch intervention).

- *Response:* BSEE has not made any changes to § 250.737(d)(3)(iv), because the relevant ROV capabilities were revised in final § 250.734(a)(4) to reduce the scope of ROV intervention function capability to critical operations only (*e.g.,* operation of each shear ram, ram locks, one pipe rams, and LMRP disconnect), similar to API Standard 53 and those specified by the commenter.

Comments Related to Proposed §§ 250.737(d)(4)(i) and (v)—API Standard 53

Summary of comments: Other commenters asserted that the additional requirements for subsea BOP testing proposed in § 250.737(d)(4)(i) and (v) conflict with API Standard 53. Under paragraph (d)(4)(i), there is not a specified timing requirement between conducting the stump testing and the on-bottom installation test; the time between these tests is a risk-based operational decision and is determined by the operator and equipment owner. The commenter says that API Standard 53 discusses initial subsea testing and specifies blind shear ram or pipe rams only need to be functioned by an ROV, and not pressure tested, and that they only have to be tested annually.

- *Response:* BSEE has not made any changes to § 250.737(d)(4). Operators are aware and test according to the 30 day timeframe, as it is based on current § 250.449(b). The timeframe between the initial test and the stump test under § 250.449(b) provides adequate time conduct each test. Furthermore, BSEE wants to minimize time between these tests to help ensure the components and BOP system as a whole can function as intended and tested. BSEE does not agree with the commenter about only testing certain components annually as this does not provide an acceptable level of confidence that the component would function as intended.

Comments Related to Proposed § 250.737(d)(5)—API Standard 53

Summary of comments: Multiple commenters expressed several concerns with requirements in proposed § 250.737(d)(5), including: The differences between API Standard 53 and this section regarding pod and control station testing; absence of a definition of ''function testing;'' confusion about the pod testing rotation; and unnecessary testing of remote stations used in emergency situations.

- *Response:* BSEE agrees with some of the concerns raised by the comments, and BSEE has revised final § 250.737(d)(5)(i)(C) by deleting the phrase ''and the pod used for pressure testing must be alternated between pressure tests'' and inserting in its place ''and 14-day pressure testing.'' This change will simplify and align the pod testing rotation with the required 14-day BOP pressure testing under the final rule and improve consistency between paragraphs (d)(5)(i)(A) and (B). Thus, it will resolve or minimize the concern raised by the comments regarding potential confusion over pod testing rotation and potential differences between the proposed requirement and API Standard 53.

In addition, BSEE has revised final § 250.737(d)(5)(ii) by replacing the phrase ''any additional control stations must be function tested every 14 days'' with ''remote panels where all BOP functions are not included (*e.g.*, life boat panels) must be function tested upon the initial BOP tests and monthly thereafter.'' This revision addresses the commenters' concerns regarding unnecessary testing of remote stations used in emergency situations by ensuring that the EDS panels are not operated every 14 days, which could increase risk to the rig crew due to the functions that those panels operate. The additional time provided by the revised language to test these remote panels will also provide more flexibility to conduct the tests at optimum times in order to limit risks to the rig crew.

These changes to final § 250.737(d)(5)(i)(C) and (d)(5)(ii) also improve consistency with API Standard 53 and help reduce any potential confusion related to testing of the pods and control stations. BSEE requires pod and control station testing, to ensure proper use of the safety equipment and to reduce the risk of non-functioning equipment, because all control stations have the potential to become critical control mechanisms during well-control events.

BSEE does not agree that there is any need to define ''function testing'' in the rules. The term has been used in the existing regulations for many years and the industry is familiar with its meaning.

Comments Related to Proposed § 250.737(d)(6) and (7)—API Standard 53

Summary of comments: Commenters observed that § 250.737(d)(6) conflicts with API Standard 53, which requires testing both the largest and smallest pipe sizes during the stump test, and then subsequently testing the smaller pipe. Commenters recommended aligning this provision with API Standard 53.

Commenters also noted that the requirement to pressure test annular type BOPs against the smallest pipe in use is a new requirement. Commenters recommended that BSEE require pressure testing of the annular-type BOPs against the largest and smallest drill pipe in use during the stump test; then, for subsea BOP pressure tests, pressure testing the annular BOPs against the smallest outside diameter drill pipe used in the hole section.

- *Response:* BSEE agrees with the commenters and has revised final § 250.737(d)(6) and (7) by replacing ''against the largest and smallest sizes of the pipe in use'' with ''against pipe sizes according to API Standard 53.'' This revision would help reduce wear of the equipment and thus improve overall integrity of the system and limit rig personnel's risks from hazardous operations such as tripping in and out of the hole.

Comments Related to Proposed § 250.737(d)(9)—BOP Function Test

Summary of comments: Commenters suggested adding to § 250.737(d)(9) that pressures tests qualify as function tests.

- *Response:* No changes to § 250.737(d)(9) are necessary. Function testing must occur every 7 days. During a pressure test, the component will have to function to close and seal before a pressure test can be completed on that component. Therefore, it would also qualify as a function test without the need for any additional language in this provision.

Comments Related to Proposed § 250.737(d)(12)—ROV Intervention Functions

Summary of comments: Multiple comments raised concerns with § 250.737(d)(12), including confusion about the ROV capabilities and testing, compatibility with the BOP stack, and ROV closing timeframes. A commenter proposed moving the requirements to § 250.737(d)(3) and deleting § 250.737(d)(12).

- *Response:* As suggested by the commenter, BSEE deleted proposed § 250.737(d)(12) from the final rule. ROV testing is sufficiently covered under final § 250.737(d)(3) which requires testing of all ROV functions.

Comments Related to Proposed § 250.737(d)(13)—API Standard 53

Summary of comments: Multiple commenters had concerns with proposed § 250.737(d)(13), including concerns about possible inconsistency between the rule and API Standard 53 with regard to testing frequency and testing autoshear and deadman systems separately. A commenter stated that if API Standard 53 is not adopted, BSEE should consider a 3-year grace period for all rigs to make upgrades to existing control systems that would allow low probability/low risk deadman testing to be performed on all rigs. A commenter stated that testing the deadman circuit is desirable, but doing such testing at present would put many operations at risk because they would have to cut off rig power to simulate a deadman test and would not have access to power on the rig if an incident occurred.

- *Response:* After considering the comments, BSEE has revised final § 250.737(d)(12) to allow the function tests for the autoshear/deadman to be combined. Many rigs have already voluntarily updated the BOP control systems with an autoshear/deadman testing circuit to reduce the risk of not having component operability during the testing.

BSEE does not agree, however, with the comment about adopting API Standard 53's testing timeframe or schedule. The final rule will require the initial on-bottom test to verify component operability on the well. This test provides assurance that the system was not damaged while running and latching the BOP on the well, and that it will operate under the conditions that it might confront in an emergency. These requirements are consistent with established longstanding practice, and operators do not need additional time to comply.

Comments Related to Proposed § 250.737(e)—BOP Shear Test

Summary of comments: A commenter suggested that the OEM should perform the shear testing at the OEM test facility and not on the unit using the drilling contractor's BOP stack. The commenter stressed that there is a risk of damaging equipment when carrying out shear tests. Equipment manufacturers should be responsible for demonstrating shearing capability as well as providing shearing data that would allow for a better understanding of the equipment shearing capability.

- *Response:* BSEE has not made any changes to § 250.737(e). BSEE agrees that testing to actually shear pipe should be done at a test facility. BSEE does not intend for, nor require, the shear testing to be done on the rig.

What must I do in certain situations involving BOP equipment or systems? (§ 250.738)

As described in the proposed rule, this section combines and revises requirements from former §§ 250.451 and 250.517 for actions that must be taken when specific situations involving BOP systems arise (*e.g.*, failure of a BOP to hold pressure during a test; needed repairs to a BOP system). The required actions include correction of problems (*e.g.*, repair or reconfiguration of the BOP), retesting the affected equipment or system, and installation of barriers prior to removal of a BOP, depending on the situation. BSEE has revised certain provisions of proposed § 250.738 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.738(a)—BOP Equipment Does Not Hold the Required Pressure During Testing

Summary of Comments: Commenters generally supported requirements in § 250.738(a) for situations when BOP equipment does not hold the required pressure during testing. Several commenters requested a change to the requirement to exclude minor issues which are easily solved or remediated. The proposed revisions are as follows: ''You must report any equipment failures, including leaks that cannot be remedied, to the District office and on the daily report as required in § 250.746.'' One commenter suggested that in addition to reporting the problem and retesting the affected equipment, the well must be secured and operations suspended until the BOP is successfully pressure tested, or repaired, or replaced in accordance with § 250.738.

- *Response:* BSEE agrees with the comment about limiting the reporting requirements, and BSEE has revised § 250.738(a) by removing the requirement for reporting to the District Manager. The reporting to the District Manager is unnecessary because the information will still be included in the daily report, and the report is available for BSEE review. BSEE has not made any other changes to this paragraph. The commenter's suggestions about what to do if you have to repair or replace the BOP if leaks are observed are covered under § 250.738(b).

Comments Related to Proposed § 250.738(b)—Repair, Replacement, or Reconfiguration of the BOP System

Summary of Comments: Commenters generally supported requirements in § 250.738(b) for repair, replacement, or reconfiguration of a surface or subsea BOP system. Several commenters requested a change from the term ''BOP system'' to ''BOP stack,'' so that a BOP surface component does not affect operations and can be replaced without having to put the well in a safe controlled condition. Other comments suggested changing the word ''certifying'' in § 250.738 (b)(3) to ''verifying.''

- *Response:* BSEE disagrees with the comment about the need to change the term ''BOP system'' in § 250.738(b) to ''BOP stack,'' because there are many other important components of a BOP system (e.g., the subsea wellhead connector, the LMRP connector, the choke and kill lines on the LMRP and on the marine riser system) that are typically not considered part of the BOP stack. Therefore, no changes are necessary to paragraph (b) in this regard. BSEE also does not agree that it is necessary to change the word ''certifying'' to ''verifying'' in paragraph (b)(3). BSEE wants to ensure the BOP is appropriate for use and the BAVO certifying report provides BSEE with important information to consider in its approval for resuming operations.

Comments Related to Proposed § 250.738(d)—BOP Control Station or Pod

Summary of Comments: Commenters generally supported requirements in § 250.738(d) for a BOP control station or pod that does not function properly. One commenter suggested revisions for clarity by suggesting the following change to paragraph (d): ''A BOP control station or pod does not function properly or no longer provides the required minimum level of redundancy.'' Another commenter stated that the term ''[function] properly'' is vague and misleading and that paragraph (d) seems to conflict with paragraph (o).

- *Response:* BSEE disagrees with the comment about making any changes to the pod requirements of § 250.738(d). The suggested phrase ''or no longer provides the required minimum level of redundancy'' is unnecessary. BSEE expects both control pods to be functional to ensure there is continuous BOP operability and control in case of emergency situations. When one of the pods is damaged or fails, the other pod must still be able to operate the BOP stack. Therefore, BSEE has not made any changes to paragraph (d).

BSEE disagrees with the commenters' concerns about the term ''[functions] properly'' in § 250.738(d). BSEE requires two pods so they are not considered redundant equipment under § 250.738(o). BSEE needs to ensure that the pods can operate the required components of the BOP stack in an emergency situation. Therefore no changes are necessary to this paragraph. If there are any concerns about a specific operational limit of your pod functionality, contact the appropriate District Manager for guidance.

Comments Related to Proposed § 250.738(e)—Tapered String

Summary of Comments: Commenters generally supported requirements in § 250.738(e) for operations with a tapered string. Comments were submitted on the requirement to install two sets of pipe rams to seal around the smaller pipe. Commenters did not see the need for a redundant ram on the smaller size pipe provided the pipe is not across the BOP stack while drilling. They stated that the annular provides a redundant means to seal against the smaller pipe. Commenters suggested revising the provision to say: ''. . . two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe in the event that this smaller pipe is across the BOP stack when drilling, or one set capable of sealing on the smaller size pipe if the pipe will not be across the BOP while drilling . . . .''

- *Response:* BSEE agrees with the comment about only requiring one set of pipe rams to seal on the smaller size pipe and has revised final § 250.738(e) by replacing the requirement to install ''two'' sets of pipe rams capable of sealing around the smaller size pipe with ''one'' set. This change does not decrease the sealing capabilities of the BOP stack because many BOP stacks use VBRs, that can seal around a greater variety of pipe sizes and, as the commenter stated, the annular is also used to seal around the smaller pipe sizes.

Comments Related to Proposed § 250.738(f)—Casing Rams or Casing Shear Rams on a Surface BOP Stack

Summary of Comments: Multiple commenters had concerns about the requirements in proposed § 250.738(f) for installing casing rams or casing shear rams in a surface BOP stack. The comments stated that the proposed requirement conflicts with API Standard 53 and implies that casing (not just drill pipe) has to be sheared. Commenters noted that API Standard 53 does not specify a need to shear casing. Commenters also recommended revisions to the language regarding testing the ram bonnets before running casing, as follows: ''. . . Test the ram bonnets' seals before running casing to the RWP or MASP\'MAWHP' plus 500 psi.''

- *Response:* BSEE agrees with the concerns related to the reference to shearing casing, not just drill pipe and revised final § 250.738(f) by removing the sentence ''[t]he BOP must also provide for sealing the well after casing is sheared.'' BSEE recognizes that this statement is not necessary in this location, as there are shearing capability requirements covered in more detail throughout this subpart (*e.g.*, § 250.732(b)).

BSEE also agrees with the commenters' concern about testing the ram bonnets and has revised paragraph (f) by replacing ''ram bonnets'' with ''affected connections.'' BSEE recognizes that testing the ram bonnets does not properly address the necessary testing to ensure BOP system integrity. Testing the affected connections is a better indicator of proper ram installation that shows system pressure integrity.

Comments Related to Proposed § 250.738(g)—Annular BOP

Summary of Comments: One comment was received on the requirements in § 250.738(g) for use of an annular BOP with a RWP less than the anticipated surface pressure. The commenter points out that paragraph (g) would allow an operator to use an annular BOP with an RWP less than the anticipated surface pressure, with BSEE approval; yet for safe operations, the annular BOP should have an RWP to match or exceed the anticipated surface pressure. Commenters suggest that DOI should provide further justification for this practice and include limitations on when this practice would be safe.

• *Response:* BSEE disagrees with the comment. Annulars are typically used with wellbore pressures less than MASP. An annular does not have any locking mechanisms to keep it closed, as do pipe and blind shear rams, and an annular will relax and not seal if the hydraulic pressure is lost. Thus, a single annular is not commonly used for well control purposes; rather, annulars are commonly used in conjunction with other MASP-rated components, such as pipe rams or blind shear rams, that can seal the well under MASP. The annular is used for quick closing and spacing of the joint so the well-control rams can close on a desired section of pipe. Because of the annular design, it is used differently than well-control rams; its design allows for pipe to be pulled through it, such as in stripping operations, and for piping spaceout in the BOP. Therefore, no changes are needed to paragraph (g).

Comments Related to Proposed § 250.738(j)—Removing the BOP Stack

Summary of Comments: One comment was submitted on the proposed requirement in § 250.738(j) to remove the BOP stack. The commenter requested that the requirement to have two barriers in place prior to BOP removal be revised to require two independent tested and verified barriers.

• *Response:* BSEE does not agree with the suggested changes. It is not necessary to revise § 250.738(j) given that barriers must be independently tested, to ensure integrity before removing the BOP stack. Nor is any change needed to clarify that the barriers must be tested before moving off location. Section 250.720(b) effectively requires that the barriers be tested before removing mud from the riser in preparation for removing the BOP stack.

Comments Related to Proposed § 250.738(k)—Deadman or Autoshear Activation

Summary of Comments: One comment was submitted on the proposed requirement in § 250.738(k) requirements related to deadman or autoshear activation. The commenter described the requirements as too prescriptive and suggested that BSEE revise paragraph (k) by replacing the phrase ''place the blind shear ram opening function in the block position prior to re-establishing power to the stack'' with the phrase ''Then you must address that possibility prior to re-establishing power to the stack.''

• *Response:* BSEE disagrees that the language should only require the operator to address the possibility of the BSR opening upon re-establishing power to the BOP stack. BSEE is aware of situations where the BSR opened upon re-establishing power to the BOP stack, and BSEE wants to ensure that the well is not unsecured prematurely and that the operator is prepared for the use of well-control measures if necessary. Therefore, no changes to § 250.738(k) are necessary.

Comments Related to Proposed § 250.738(l)—BOP Test Ram

Summary of comments: Multiple comments were submitted on the proposed § 250.738(l) requirements that would apply if a test ram is used. A commenter had concerns about the maximum pressure for the approved ram test for the well. Commenters also requested that hydraulic connectors, wet-mate connectors, and all stabs be exempted from the test.

• *Response:* BSEE agrees with most of the commenters' concerns and has revised final § 250.738(l) by replacing that entire paragraph with a requirement that the wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed, and providing that this can be done by: Testing the wellhead/BOP connection to the maximum MASP plus 500 psi for the well upon installation; or pressure testing each casing to the MASP plus 500 psi for the next hole section; or some combination of those two tests. These changes align the regulations with current BSEE policy and practice related to testing the wellhead/BOP connections. These changes provide clarity to BSEE's testing requirements. BSEE also agrees, in part, with the need to remove the hydraulically operated BOP components language of paragraph (l). BSEE removed this provision in this paragraph because it is sufficiently covered under § 250.737(d)(4).

Comments Related to Proposed § 250.738(o)—Redundant Components

Summary of comments: Multiple comments were submitted on the proposed § 250.738(o) requirements for installation of redundant components for well control in BOP systems. The comments suggested that BSEE revise the paragraph (o) to require a one-time identification and certification submitted with documentation under proposed § 250.731, including identification of all additional redundant components and certification using failure modes analysis by a BAVO that the failure of those additional redundant components will not impact the BOP in a way that will make it unfit for well-control purposes. One other commenter suggested that the requirement to submit a report each time a redundant component fails can actually be a deterrent to operators who would otherwise want to achieve higher safety levels by incorporating redundancy beyond the required levels.

• *Response:* BSEE disagrees with the commenters' concerns about the failure of redundant components. If redundant components are installed and planned to be used as necessary, they need to be able to fully function and operate (similarly to the required components) as intended. The operator has the option to utilize the redundant systems without having to pull the stack, as long as the failure does not interfere with the required functionality. Therefore, no changes to § 250.738(o) are necessary.

Comments Related to Proposed § 250.738(p)—Bottom Hole Assembly

Summary of comments: Comments were submitted on the proposed requirements in § 250.738(p) for tripping the BOP and bottom hole assembly positioning. Most commenters raised concerns about the requirement to ensure well stability for 30 minutes prior to positioning the bottom hole assembly. They stated that determining stable well conditions should not be regulated to a prescribed time requirement, and that other methods should be permitted, such as flow checks, tripping volumes, or well monitoring. Comments were also raised about the using the term ''immediate'' with regard to removing the bottom hole assembly from across the BOP in the event of a well control or emergency situation. The commenters' suggestions for revision to paragraph (p) included deleting the word ''immediate'' and stating in the well-control plan that removing non-shearables from across the BOP stack is to be done as efficiently as possible without jeopardizing the safety of personnel. The comment recommended that this removal occur prior to positioning the bottom hole assembly into the BOP. Another comment recommended that this provision require a minimum 5-minute flow check on the trip tank to confirm that the well is not flowing, after which the bottom hole assembly may be tripped through the BOP.

- *Response:* BSEE agrees with most of the commenters' suggestions and has revised final § 250.738(p) by removing the reference to the 30 minute timeframe and deleting the word ''immediate'' before ''removal of the bottom hole assembly.'' BSEE recognizes there are many suitable methods to ensure that a well is stable, as the comments suggested. BSEE understands that, for every well, the bottom hole assembly will be across the BOP stack, and it is BSEE's intention to ensure that there are procedures in place to limit this exposure across the BOP stack at some point. BSEE removed ''immediate'' from the regulatory text to enable appropriate actions to be taken to make sure the well is secure and to ensure safety.

What are the BOP maintenance and inspection requirements? (§ 250.739)

As provided for in the proposed rule, this section combines and revises requirements from several sections of the existing regulations regarding maintenance and inspection of BOPs. This section now requires BOP maintenance and inspection procedures to meet or exceed OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations. It also establishes procedures for a complete breakdown and inspection of the BOP and associated components every 5 years, which can be done in phased intervals (a change from the proposed rule), and requires that the inspection be documented and that a BAVO be present during the inspection. In addition, the final rule requires frequent visual inspections of all BOPs, and that personnel who maintain, inspect, or repair BOPs or other critical components meet certain training criteria. BSEE has revised proposed § 250.739 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.739(a)—Critical Components and Recognized Engineering Practices

Summary of comments: Several commenters requested clarification of the phrases ''critical components'' and ''recognized engineering practices and industry standards'' in proposed § 250.739(a), stating that the terms are vague and open to inconsistent interpretation. They also requested a description of what the deliverables would be for conformance to API Standard 53. Several commenters requested that BSEE revise paragraph (a) to require that operators maintain and inspect their BOP systems, as defined in API Standard 53 1.1.2, to ensure that the equipment functions as designed. The commenters also suggested that all BOP maintenance and inspections must meet the equipment owner's preventative maintenance program, and that operators must: Document how they met or exceeded the provisions of API Standard 53; maintain complete records to ensure the required traceability of the equipment; and record the results of the inspections and maintenance actions; and make all records available to BSEE upon request.

- *Response:* BSEE agrees with the comment about defining all critical components and has revised final § 250.739(a) by replacing ''all critical components'' with ''BOP stack equipment.'' However, BSEE does not agree with the commenters' recommendation for revisions to paragraph (a) concerning the references to API Standard 53 and owners' preventative maintenance programs. This section already requires the BOP maintenance and inspections to meet or exceed API Standard 53. Thus, the commenters' proposed reference to the owner's preventative maintenance program would not be appropriate. BSEE is aware of major differences between different owners' preventative maintenance programs. BSEE realizes that such programs are useful to help plan and ensure maintenance and inspections are completed. But due to the differences between company-specific programs, BSEE cannot rely on a reference to such programs in paragraph (a) to satisfy the BOP maintenance and inspection requirements of this provision.

Comments Related to Proposed § 250.739(b)—BOP Breakdown and Inspection

Summary of comments: Multiple commenters expressed concerns with the 5-year testing provision in proposed § 250.739(b), which would have required complete breakdown and inspection of the BOP system and every associated component at one time. Most industry commenters did not object to a 5-year inspection requirement for each BOP component, *provided* that the inspections could be staggered, or phased, over time, as provided in API Standard 53. Commenters expressed concern that requiring all components to be inspected at one time would put too many rigs out of service, potentially for long periods of time, with substantial economic impacts.

- *Response:* BSEE agrees with the commenters' concerns about performing the 5-year major inspection of the entire BOP system and all components at one time. Accordingly, BSEE has revised final § 250.739(b) by: Allowing the complete breakdown and inspection to be performed in phased intervals; adding clarification that all system and component inspection dates must be tracked, documented, and available on the rig; and including new paragraphs (b)(1), (2), and (3) describing the types of actions that could be used as start dates for the inspection intervals. The final regulatory language will allow a phased approach, as long as there is proper documentation and tracking to ensure that BSEE can verify that each applicable component has had a major inspection within the preceding 5 years. Proper documentation will improve BSEE oversight, as compared to current practice, while a phased approach would avoid the possibility of long shut downs. BSEE added the list of actions that can be used to start the 5-year timeframe, which are consistent with API Standard 53, to provide additional clarity.

Comments Related to Proposed § 250.739(d)—Personnel Training

Summary of comments: Several commenters raised concern with the proposed § 250.739(d) training requirements, stating that: BOP equipment OEMs do not specify qualification and training criteria; OEM training courses do not address every aspect of maintenance and troubleshooting that is encountered in the field; and training is covered under the SEMS program requirements.

Commenters suggested revisions to proposed § 250.739(d), including requiring: Personnel who maintain, inspect, or repair BOPs or other critical components to meet the qualifications and training criteria specified by the equipment owner; consideration of OEM guidelines; and performing maintenance, inspection, and repair in accordance with API Standard 53.

• *Response:* BSEE agrees with several of the suggestions in these comments and has revised final § 250.739(d) by requiring that personnel be trained in accordance with all applicable training requirements in subpart S, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in final subpart G. These revisions, made in response to the comments, clarify BSEE's intent to ensure that all personnel are trained properly for the equipment that they will maintain, inspect, or repair.

Comments Related to Proposed § 250.739(e)—Retention of Equipment Design Records

Summary of comments: Several commenters raised concerns with the retention of equipment design records proposed in § 250.739(e) and suggested alternative language. Commenters stated that equipment designs are proprietary information of the OEM; therefore, the design records can only be retained by the OEM. Further, commenters stated that retention of this information is required by the OEM to meet API manufacturing specifications. Commenters also stated that modifications to the functional design of the stack are maintained by the equipment owner; therefore, it should be the responsibility of the equipment owner to maintain all required records.

• *Response:* BSEE agrees with the commenters' concerns about retention of equipment design records and has revised the last sentence in final § 250.739(e) to require that the operator ensure that all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment. BSEE understands that the equipment OEMs may retain proprietary design documents that are not available to others. Therefore, BSEE replaced ''design'' with ''schematics'' and revised the operator's responsibility from ''maintaining'' design records to ''ensuring'' that the equipment schematics, and other specified records, are kept at an onshore location. These revisions will address the commenters' concerns that only the OEM may have the original design records and that only the equipment owner may have design modification records. BSEE understands that the equipment schematics are usually made available by OEMs. Under the revised language, the operator is only responsible for ensuring that the schematics and other specific records are located onshore (given that records located on the rig unit may become inaccessible or lost in the event of an emergency), whether or not the onshore location for each of the relevant records is the operator's, equipment owner's, or the OEM's.

Records and Reporting

What records must I keep? (§ 250.740)

As provided for in the proposed rule, this section incorporates and clarifies recordkeeping requirements from former § 250.466 applicable to all operations covered under final subpart G. This section requires that well records, including a daily report for each well, must be kept onsite during well operations. Well records must include, among other things, complete information on: Well operations, all tests conducted, and RTM data; oil, gas and mineral deposits encountered; casings; and significant malfunctions or problems. BSEE has revised proposed § 250.740 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.740(a)—RTM and Well Data

Summary of comments: A commenter contested the RTM aspects of the rule in proposed § 250.740(a). This commenter indicated that BSEE uses ''real-time monitoring'' to encompass both well-site and remote monitoring at an onshore location, which are two separate activities. The commenter stated that well-site monitoring is a standard practice, whereas remote monitoring is not. The commenter recommended replacing ''real-time monitoring data'' with ''well data.'' Another commenter asked whether this provision would require additional RTM (presumably beyond what proposed § 250.724 would require).

• *Response:* BSEE disagrees with the suggestion to remove the reference in paragraph (a) to the RTM data. BSEE is requiring RTM data in final § 250.724, and § 250.740(a) is intended to require operators to preserve the RTM data collected pursuant to § 250.724. BSEE is not imposing additional RTM obligations beyond those required in § 250.724. To clarify that point, BSEE has added to final § 250.740(a), after the reference to real-time monitoring data, ''as required by § 250.724.''

BSEE also disagrees with the suggestion that paragraph (a) be limited to ''well data'' (presumably because the commenter believed that the revision would eliminate the need to retain records onshore related to ''remote'' RTM). Section 250.724 requires that RTM data be gathered offshore to be transmitted to an onshore location. BSEE may need to review the RTM data at the onshore location if there is an incident. Similarly, BSEE may need to review the retained RTM data onshore after an incident, in order to verify conditions at the time of the incident and to assist in an incident investigation. If the commenter's suggested revision was intended to limit the data BSEE can review onshore, then BSEE rejects that suggestion.

Comments Related to Proposed § 250.740(d)—Kind, Weight, Size, Grade, and Setting Depth of Casing

Summary of comments: Commenters recommended that BSEE clarify the information required by proposed § 250.740(d), regarding records on kind, weight, size, grade, and setting depth of casing. The comments suggested that BSEE revise paragraph (d) to read: ''Information relative to casing and cementing such as weight, size, grade, and setting depth of casing and volume and type of cement pumped along with cementing pressures and displacements.''

• *Response:* BSEE does not agree that the revision suggested by the commenters is necessary or would provide any additional clarity for this recordkeeping requirement. The scope of these records is already clarified by the detailed requirements in final § 250.415(a)(3) regarding information about cementing and casing programs that must be provided in APDs. BSEE expects that records specified in § 250.740(d) will include the information specified in § 250.415(a)(3).

Comments Related to Proposed § 250.740(f)—Any Significant Malfunction or Problem

Summary of comments: A commenter asserted that the requirement in proposed § 250.740(f) regarding recordkeeping for ''any significant malfunction or problem'' is ambiguous. This commenter recommended that BSEE provide some examples of what type of malfunction or problem for which it suggests keeping records, noting that there is already a requirement for equipment failure reporting, and that well-control events and other drilling-related problems are documented in the daily well reports.

• *Response:* BSEE does not agree that this provision is ambiguous or that the recordkeeping required by § 250.740(f) is duplicative of other reporting requirements in this rule. Although there are several specific reporting requirements in this rule for subjects similar to the records required by § 250.740(f) (*e.g.*, § 250.738(a) requires reporting of irregularities or problems resulting from pressure testing), there are no specific record keeping requirements for all significant malfunctions or problems. BSEE needs to ensure that records of all significant malfunctions or problems are maintained so that BSEE can review the records as needed to assist in the investigation of any incident or significant problem. The requirements for reporting specific events to BSEE, or for keeping other records, does not duplicate the recordkeeping under § 250.740(f) since copies of reports or records under other provisions can be used to satisfy § 250.740(f). Therefore, BSEE has not made any changes to that paragraph.

Comments Related to Proposed § 250.740(g)—Information Required by the District Manager

Summary of comments: Commenters requested that BSEE revise proposed § 250.740(g) to clarify what additional information may be required and to define the scope of the District Manager's authority to request additional records. These commenters suggested defining the scope of information requests as information sought ''in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.''

• *Response:* Like similar provisions throughout 30 CFR part 250, § 250.740(g) is intended to give District Managers the necessary flexibility and discretion to require additional information as needed in specific cases to fulfill the purposes of the regulation. Of course, the District Managers must exercise that discretion in a manner consistent with BSEE's statutory authority and responsibility under OCSLA, including—as the commenter suggested—conservation of natural resources and protection of safety and the environment on the OCS. In addition, the District Manager must exercise the discretionary authority of paragraph (g) in a way that serves the purpose of § 250.740; *i.e.*, the maintenance of records for each well that provide relevant information about the specific well and operations, its geological conditions and related circumstances, and any significant problems or malfunctions. Accordingly, BSEE has revised final § 250.740(g) to clarify the scope and purpose of the District Manager's authority.

How long must I keep records? (§ 250.741)

As provided for in the proposed rule, this section incorporates the same requirements as former § 250.467 regarding how long records related to drilling, casing and liner pressure tests, diverter and BOP tests, and completion and workover activities must be kept. This section also requires that records related to RTM data must be kept for 2 years after completion of operations. There are no changes to this proposed section in the final rule.

Comments Related to Proposed § 250.741—Electronic Recordkeeping

Summary of comments: A commenter recommended that BSEE revise §§ 250.467 and 250.741 to require records to be kept in electronic form for the life of the well. Longer record retention periods will ensure that important records are maintained and available to the operator and BSEE for future work on the well or during an investigation.

• *Response:* BSEE disagrees with the commenter that all of the records identified in § 250.741 (which replaces former § 250.467) should be required to be kept for the life of the well. BSEE already requires that certain data be retained for the life of the well, as in final § 250.741(c). BSEE determined that the specific retention timeframes for the information listed in § 250.741(a) through (c) are reasonable and appropriate for the purpose of allowing BSEE to review the information in the event of an incident or investigation or to determine compliance with requirements of this subpart. Those timeframes are identical to those in the former § 250.467 (with the exception of the new requirement for RTM data), which has been in effect for many years, and BSEE is not aware of any instances in which those timeframes have proven inadequate. Accordingly, BSEE does not see a need at this time for expanding those timeframes as suggested by the commenter.

Comments Related to Proposed § 250.741(b)—Casing and Liner Pressure Tests, Diverter Tests, BOP Tests, and RTM Data

Summary of comments: A commenter asserted that retention of the identified records under § 250.741(b)—i.e., casing and liner pressure tests, diverter tests, and RTM data—for 2 years is not necessary on a decommissioning operation after the well has been plugged, although the commenter acknowledged that the information may need to be kept longer in the event of a re-drill or sidetrack. Another commenter recommended that BSEE revise paragraph (b) to require the operator to retain BOP RTM data while conducting operations on the well, and require the owner of the equipment to retain the BOP data for a period of 2 years.

• *Response:* The record retention requirements in final § 250.741(b) are well established under former § 250.467, and BSEE is unaware of any problems with those record retention requirements with respect to decommissioning operations. In addition, the commenter that suggested revising the proposed requirement for retention of RTM data did not provide any support for that suggestion. And BSEE, based on its experience with the longstanding records retention requirements for the test data specified in former § 250.467(b), sees no reason why the operator should not retain RTM data for 2 years. Therefore, BSEE has not made the suggested changes to final § 250.741.

What well records am I required to submit? (§ 250.742)

This section contains requirements from former § 250.468 regarding submission to BSEE of records related to well-logging operations, certain well surveys, velocity profiles, and core analyses. The remainder of the requirements from former § 250.468, regarding well activity reporting, are included in final § 250.743. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language.

What are the well activity reporting requirements? (§ 250.743)

As provided for in the proposed rule, this section includes requirements from former § 250.468(b) and (c) regarding submission of WARs for drilling operations in the GOM and Pacific or Alaska regions, respectively. It also codifies reporting procedures contained in BSEE NTL 2009–G20, *Standard Reporting Period for the Well Activity Report*, and BSEE NTL 2009–G21, *Standard Conditions of Approval for Well Activities*.

BSEE will rescind any NTLs that are superseded by this section in the final rule. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language.

What are the end of operation reporting requirements? (§ 250.744)

As described in the proposed rule, this section combines provisions from several sections of the existing regulations, codifies certain procedures from NTL 2009–G21, *Standard Conditions of Approval for Well Activities*, and clarifies the contents of the EOR (Form BSEE–0125). This information provides BSEE with important well data and a better understanding of the well operations and conditions. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language.

What other well records could I be required to submit? (§ 250.745)

As provided for in the proposed rule, this section incorporates the requirements of former § 250.469 regarding well records that a District Manager or Regional Supervisor may require an operator to submit. BSEE received no substantive comments on this provision of the proposed rule and has made no changes to the proposed language.

What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers? (§ 250.746)

As described in the proposed rule, this section combines and clarifies requirements from several sections of the existing regulations regarding recordkeeping for testing of casings, liners and BOPs and for BOP and marine riser inspections. It also specifies information that must be included in the daily report. BSEE has made certain revisions to proposed § 250.746 in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed §§ 250.746(a) and (b)—Test Pressure Records and Pressure Charts

Summary of comments: A commenter recommended revising § 250.746(a) and (b)—regarding test pressure records and pressure charts—to allow the use of digital recorders as these are also an acceptable method for recording pressure tests.

• *Response:* BSEE agrees with the commenter and revised final § 250.746(a) and (b) to include digital recorders. This change also aligns these provisions more closely with the digital pressure testing required in final § 250.737(c).

Comments Related to Proposed § 250.746(d)—Identification on the Daily Report of the Control Station and Pod Used During a BOP Test

Summary of comments: Commenters observed that the requirement in proposed § 250.746(d)—requiring identification on the daily report of the control station and pod used during a BOP test—apparently applies to all types of operations; however, pods are not found on equipment (such as surface stacks, coiled tubing units, and snubbing units) associated with certain operations. The commenters suggested that BSEE revise this paragraph to address this concern.

• *Response:* BSEE disagrees with the comment. It is BSEE's intention that the requirement to identify the pod used during testing applies only to testing that actually uses a pod; in fact the proposed and final § 250.746(d) provide examples of equipment (i.e., coiled tubing and snubbing units) that would not require identification of a pod.

Comments Related to Proposed § 250.746(e)—Notifying the District Manager of Leaks

Summary of comments: Commenters stressed that the proposed requirement under § 250.746(e) to immediately notify the District Manager of any leaks associated with BOP or control system testing is unnecessary, especially for equipment failures during BOP testing. Other commenters asserted that the proposal to suspend operations when any problems or irregularities are observed during testing may be unsafe, and that operators need to be able to handle minor problems and issues internally. Commenters requested that BSEE clarify under what circumstances leaks are considered problems. A commenter also requested that BSEE clarify what components are included in ''BOP Control Systems'' and recommended rewording the requirement for reporting ''any leaks'' associated with BOP or control system testing to require reporting of ''unresolved leaks'' associated with such testing.

• *Response:* BSEE agrees with the commenters' suggestion regarding the requirement for ''immediate'' notification to the District Manager of any leaks and revised final § 250.746(e) by removing that requirement. This proposed notification is unnecessary because the same information must be documented in the WAR, which former § 250.468 and final § 250.743 require to be submitted to BSEE on a weekly basis in the Gulf region and on a daily basis in the Alaska region.

BSEE also agrees with the comment that it is not necessary, and in some cases may be imprudent, to suspend operations for ''any problems'' and revised § 250.746(e) to state that ''[i]f any problems that cannot be resolved promptly are observed during testing. . .'' you must suspend operations. This change will limit the amount of shut-ins that might have occurred under the proposed language even though the problem could have been resolved before posing any significant risk. The problem should be evaluated first, and then, if it is determined that repairs or other resolution are necessary and cannot be completed promptly, operations must be suspended.

BSEE has also deleted the phrase ''are considered problems or irregularities and'' from final § 250.746(e) because not all leaks are considered problems and some leaks may not affect BOP system operability.

BSEE is not specifically defining what a BOP ''control system'' consists of, however, BSEE does not want to limit an operator that may have elements in its control system that are not typically found in other BOP control systems. In general, however, BSEE expects that most BOP control systems will be consistent with API Standard 53's description of that term.

Comments Related to Proposed § 250.746(f)—Record Retention

Summary of comments: A commenter recommended that, under proposed § 250.746(f), BSEE not require the records for pressure testing to be kept on the rig/facility after the operation has concluded. Rather, the operator should keep these records at an alternative location (office, records storage facility).

• *Response:* BSEE has not made the commenter's suggested revision to this section because the documentation may be necessary and must be available on the rig for incident investigation and auditing purposes.

Subpart P—Sulfur Operations

Well-Control Drills (§ 250.1612)

As provided for in the proposed rule, this section updates the references for the drilling crew requirements under final § 250.711. BSEE received no substantive comments on this provision of the proposed rule and has made no changes to the proposed language in the final rule.

Subpart Q—Decommissioning Activities

What are the general requirements for decommissioning? (§ 250.1703)

As provided for in the proposed rule, paragraph (b) of existing § 250.1703 includes a new requirement that all permanent packers and bridge plugs must comply with API Spec. 11D1. It also requires that decommissioning operations must follow all applicable requirements in new Subpart G. BSEE has revised paragraph (b) in the final rule as discussed in the comment responses for this section and in part V.C of this document.

Comments Related to Proposed § 250.1703(b)—Temporary Packers and Bridge Plugs

Summary of comments: Commenters stated that, under proposed § 250.1703, compliance with API Spec. 11D1 should not be required for temporary packers and bridge plugs (i.e., those used for well servicing). Commenters stressed that API Spec. 11D1 does not apply to temporary packers and bridge plugs.

• *Response:* BSEE agrees with the commenters that this section should apply only to permanently installed packers and bridge plugs and has revised final § 250.1703 accordingly.

Comments Related to Proposed § 250.1703(f)—Well Abandonment

Summary of comments: A commenter noted that § 250.1703(f) adds a reference to the requirements of new subpart G, which would make subpart G applicable to decommissioning. The commenter noted that well abandonments are normally considered as part of the plan only for exploration programs and not development programs.

• *Response:* BSEE does not agree with this comment, and has not made the suggested changes to § 250.1703 in the final rule, because some of the equipment used in drilling, workover, and completion operations is also used for decommissioning (e.g., MODUs and BOPs). That equipment must meet the requirements necessary to ensure safety and environmental protection without regard to the types of well operations in which the equipment is used.

When must I submit decommissioning applications and reports? (§ 250.1704)

As provided for in the proposed rule, paragraph (g) of existing § 250.1704 is revised by removing current paragraphs (g)(2), (4), and (6) and the associated instructions in the third column, as well as by revising the numbering of current paragraphs (g)(3) and (5) to paragraphs (g)(2) and (3), respectively, and by updating the applicable citations. Also paragraph (h) clarifies when operators must submit an EOR rather than an APM. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language in the final rule.

What BOP information must I submit? (§ 250.1705)

As provided for in the proposed rule, this section is removed and reserved. The content of this former section is moved to final §§ 250.731 and 250.732. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

Coiled Tubing and Snubbing Operations (§ 250.1706)

This section of the existing regulation was titled ''What are the requirements for blowout prevention equipment?'' As provided for in the proposed rule, this section is re-titled and moves paragraphs (a) through (e) of the former section to final §§ 250.730, 250.733, 250.734, and 250.735. Remaining paragraphs (f) through (h) of the existing regulation are redesignated as paragraphs (a) through (c). BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language in the final rule.

What are the requirements for blowout preventer system testing, records, and drills? (§ 250.1707)

This section is removed and reserved. As described in the proposed rule, the content of this former section is moved to final §§ 250.711, 250.736, 250.737, and 250.746. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

What are my BOP inspection and maintenance requirements? (§ 250.1708)

This section is removed and reserved. As provided for in the proposed rule, the content of this former section is moved to final § 250.739. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

What are my well-control fluid requirements? (§ 250.1709)

This section is removed and reserved. As provided for in the proposed rule, the content of this former section is moved to final § 250.720. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

How must I permanently plug a well? (§ 250.1715)

As provided for in the proposed rule, BSEE proposed to revise paragraph (a)(3)(iii)(B) of existing § 250.1715 to require that ''casing'' bridge plugs must be set 50 to 100 feet above the top of the perforated interval. After consideration of comments on the proposed rule, BSEE has made no changes to the proposed language in the final rule.

Comments Related to Proposed § 250.1715—Abandonment and Isolating Zones

Summary of comments: A commenter suggested revising § 250.1715 to add new regulatory requirements for abandonment and isolating zones.

• *Response:* This comment and the suggested revision to § 250.1715 are outside the scope of this rulemaking, and the suggested changes are not necessary or appropriate for consideration at this time.

After I permanently plug a well, what information must I submit? (§ 250.1717)

This section is removed and reserved. The content of this former section is moved to final § 250.744. BSEE received no comments on the proposed removal and reservation of this section and the final rule implements that action.

If I temporarily abandon a well that I plan to re-enter, what must I do? (§ 250.1721)

As provided for in the proposed rule, paragraph (g) is removed from existing § 250.1721 and former paragraph (h) is redesignated as paragraph (g). The content of former paragraph (g)—regarding submission of an APM within 30 days after temporarily plugging a well—has been moved to final § 250.744. BSEE received no substantive comments on this provision of the proposed rule and made no changes to the proposed language in the final rule.

VII. Derivation Tables

The following tables are intended to provide information about the derivation of new requirements in subparts A, B, D, E, F, G, P, and Q of part 250. These tables illustrate:

— The destination of various current requirements.
— The organization and content of the revisions.

These tables do not provide definitive or exhaustive guidance, and should be used as reference material and in conjunction with the section-by-section discussion and regulatory text of this rule.

The following sections in 30 CFR part 250, subparts D, E, F, and Q have been [Removed and/or Reserved] according to the following table.

Subpart	Removed and/or reserved in 30 CFR part 250
D	401, 402, 403, 406, 417, 424, 425, 426, 440 through 451, 466 through 469.
E	502, 506 through 508, 515 through 517.
F	602, 606 through 608, 615, 617, 618.
Q	1705, 1707 through 1709, 1717.

The rule makes changes as outlined in the following table:

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Prior Regulations Section	New Rule Section	Nature of Change
		(k) to help ensure the well's structural integrity and submission of any additional information required by the District Manager.
250.415(a)	250.415(a)	Revised paragraph (a) for casing information in all sections for each casing interval.
250.416	250.416(a), (b); 250.730; 250.731; 250.732	Revised to remove only the BOP descriptions in the regulatory text and section heading.
250.417	250.713	Removed - similar language found in new subpart G.
250.418(g)	250.418(g)	Revised to include a description of how far below the mudline the operator proposes to displace cement in the request for approval; revised citation.
250.420	250.420	Revised the introductory paragraph to include applicable casing and cementing requirements in subpart G; added new paragraph (a)(6) to require adequate centralization to ensure proper cementation; added new paragraph (b)(4) requiring District Manager approval before installing a different casing than what was approved in the APD; modified paragraph (c) requiring the use of a weighted fluid.
250.421	250.421(b) and (f)	Revised paragraph (b) so casing would have to be set immediately and set above the encountered zone, even if it is before the planned casing point if oil or gas or unexpected formation pressure arises. Revised paragraph (f) to no longer allow liners to be installed as conductor casing.
250.423	250.423	Revised the section heading and removed the pressure testing and negative pressure testing requirements; added clarification about latching mechanisms. Edited the remaining paragraphs of

Prior Regulations Section	New Rule Section	Nature of Change
		§ 250.423 for organization.
250.423(a) and (c)	250.721	Removed - similar language found in new subpart G.
250.424	250.722	Removed - similar language found in new subpart G.
250.425	250.721	Removed - similar language found in new subpart G.
250.426	250.746	Removed - similar language found in new subpart G.
250.427(b)	250.427(b)	Revised paragraph (b) to clarify that operators must maintain a safe drilling margin.
250.428	250.428	Revised paragraphs (b) through (d). Paragraph (b) requires approval for hole interval drilling depth changes greater than 100 ft. TVD, and the submittal of a PE certification that the certifying PE reviewed and approved the proposed changes; paragraph (c) clarifies requirements when there is any indication of an inadequate cement job; and paragraph (d) clarifies that if there is an inadequate cement job, the District Manager has to review and approve all remedial actions; that the changes to the well program are reviewed, approved, and certified by a PE; and any other requirements of the District Manager. New paragraph (k) adds requirements concerning the use of valves on drive pipe during cementing operations.
250.440	250.730	Removed - similar language found in new subpart G.
250.441	250.733; 250.735	Removed - similar language found in new subpart G.
250.442	250.734	Removed - similar language found in new subpart G.
250.443	250.734; 250.735	Removed - similar language found in new Subpart G.

Prior Regulations Section	New Rule Section	Nature of Change
250.443(c) and (d)	250.733	Removed - similar language found in new subpart G.
250.444	250.736	Removed - similar language found in new subpart G.
250.445	250.736	Removed - similar language found in new subpart G.
250.446	250.739	Removed - similar language found in new subpart G.
250.447	250.737	Removed - similar language found in new subpart G.
250.448	250.737	Removed - similar language found in new subpart G.
250.449	250.737	Removed - similar language found in new subpart G.
250.450	250.746	Removed - similar language found in new subpart G.
250.451	250.738	Removed - similar language found in new subpart G.
250.456(k)	250.456(j)	Redesignated.
250.456(j)	250.720	Removed - similar language found in new subpart G.
NEW	250.462	New section heading and requirements to demonstrate deepwater well containment.
250.462	250.710 and 250.711	Removed heading and requirements for well-control drills - similar language found in new subpart G.
250.465(b)(3)	250.465(b)(3)	This paragraph was revised to update the citation for the EOR form, BSEE-0125.
250.466	250.740	Removed - similar language found in new subpart G.
250.467	250.741	Removed - similar language found in new subpart G.
250.468(a)	250.742	Removed - similar language found in new subpart G.
250.468(b) and (c)	250.743	Removed - similar language found in new subpart G.
250.469	250.745	Removed - similar language found in new subpart G.
Subpart E		
250.500	250.500	Revised section heading and

Prior Regulations Section	New Rule Section	Nature of Change
		requirements to encompass General Requirements and direct compliance with new subpart G where applicable.
250.502	250.723	Removed - similar language found in new subpart G.
250.506	250.710	Removed - similar language found in new subpart G.
250.514(d)	250.720	Removed - similar language found in new subpart G.
250.515	250.731; 250.732	Removed - similar language found in new subpart G.
250.516	250.730; 250.733; 250.734; 250.735; 250.736	Removed - similar language found in new subpart G.
250.517	250.711; 250.737, 250.738, 250.739; 250.746	Removed - similar language found in new subpart G.
250.518	250.518(e), (f)	Removed paragraph (b) and redesignated the remaining paragraphs. Added new paragraphs (e) and (f) to add API Spec. 11D1, packer and bridge plug requirements, and a description of calculations of packer setting depth.
250.518(b)	250.722	Redesignated and revised to include additional requirements for prolonged operations.
Subpart F		
250.600	250.600	Revised section heading and requirements to encompass General Requirements and direct compliance with new subpart G where applicable.
250.602	250.723	Removed - similar language found in new subpart G.
250.606	250.710	Removed - similar language found in new subpart G.
250.614(d)	250.720	Removed - similar language found in new subpart G.
250.615	250.731; 250.732	Removed - similar language found in new subpart G.

Prior Regulations Section	New Rule Section	Nature of Change
250.616(a) through (e)	250.730; 250.733; 250.734; 250.735; 250.736	Removed - similar language found in new subpart G.
250.616(f) through (h)	250.616(a) through (c)	Redesignated with no changes made to regulatory text.
250.617	250.711; 250.737; 250.746	Removed - similar language found in new subpart G.
250.618	250.739	Removed - similar language found in new subpart G.
250.619	250.619	Removed paragraph (b) and redesignated the section. Added new paragraphs (e) and (f) to add packers and bridge plug requirements, API Spec. 11D1, and a description of calculations of packer setting depth.
250.619(b)	250.722	Redesignated and revised to include additional requirements for prolonged operations.
New Subpart G		
General requirements		
NEW	250.700	New section describing what operations and equipment are subject to the requirements.
250.408	250.701	Similar language pertaining to alternative procedures or equipment.
250.409	250.702	Similar language pertaining to departures.
250.401	250.703	Similar language containing requirements to keep wells under control.
Rig Requirements		
250.462; 250.506; 250.606	250.710	Similar language was revised and incorporated into this section about instructions for rig personnel.
250.462; 250.517; 250.617; 250.1707	250.711	Similar language was revised and incorporated into this section about well-control drills.
250.403	250.712	Similar language was revised and incorporated into this section about rig movement notifications.

Prior Regulations Section	New Rule Section	Nature of Change
250.417	250.713	Similar language was revised and incorporated into this section about MODUs or lift boat requirements for well operations.
NEW	250.714	New section about dropped objects plans.
NEW	250.715	New section about GPS for MODUs and jack-ups.
Well Operations		
250.402; 250.456(j); 250.514(d); 250.614(d); 250.1709	250.720	Similar language was revised and incorporated into this section about securing a well.
250.423(a), (c); 250.425	250.721	Similar language was revised and incorporated into this section about pressure testing casing and liners.
250.424; 250.518; 250.619	250.722	Similar language was revised and incorporated into this section pertaining to prolonged well operations.
250.406; 250.502; 250.602	250.723	Similar language from §§ 250.406, 250.502, and 250.602 was revised and incorporated into this section relating to safety measures on a platform producing wells or other hydrocarbon flow.
NEW	250.724	New section relating to RTM requirements.
Blowout Preventer (BOP) System Requirements		
250.416; 250.440; 250.516; 250.616(a) through (e); 250.1706	250.730	Similar language was revised and incorporated into this section about general requirements for BOP systems and their components.
250.416; 250.515; 250.615; 250.1705	250.731	Similar language was revised and incorporated into this section about submittal requirements for information about BOP systems and their components.
250.416; 250.515; 250.615; 250.1705	250.732	Similar language was revised and incorporated into this section relating to third-party information for BOP systems and their components.
250.441; 250.443(c), (d); 250.516;	250.733	Similar language was revised and incorporated into this section and

Prior Regulations Section	New Rule Section	Nature of Change
250.616(a) through (e); 250.1706		new language was added relating to requirements for a surface BOP stack.
250.442; 250.443(c), (d); 250.516; 250.616(a) through (e); 250.1706	250.734	Similar language was revised and incorporated into this section and new language was added relating to requirements for a subsea BOP system.
250.441; 250.443; 250.516; 250.616; 250.1706	250.735	Similar language was revised and incorporated to this section and new language was added relating to equipment and systems all BOPs must have.
250.444; 250.445; 250.516; 250.616(a) through (e); 250.1707	250.736	Similar language was revised and incorporated into this section pertaining to requirements for choke manifolds, kelly valves, inside BOPs, and drill string safety valves.
250.447; 250.448; 250.449; 250.517; 250.617; 250.1707	250.737	Added new language and similar language was revised and incorporated into this section relating to BOP system testing requirements.
250.451 and 250.517	250.738	Added new language and similar language was revised and incorporated into this section for situations arising involving BOP equipment or systems.
250.446; 250.517; 250.618; 250.1708	250.739	Similar language was revised and incorporated into this section pertaining to BOP maintenance and inspection requirements.
Records and Reporting		
250.466	250.740	Redesignated and revised the types of records to keep.
250.467	250.741	Redesignated and added records relating to RTM data.
250.468(a)	250.742	Redesignated.
250.468(b) and (c)	250.743	Redesignated and revised to include more requirements for the well activity reporting.
250.465; 250.1712; 250.1717	250.744	Redesignated and revised to include additional end of operation

Prior Regulations Section	New Rule Section	Nature of Change
		reporting requirements.
250.469	250.745	Redesignated and revised to update references.
250.426; 250.450; 250.517; 250.617; 250.1707	250.746	Similar language was revised and incorporated into this section pertaining to recordkeeping for casing, liner, and BOP tests.
Subpart P		
250.1612	250.1612	Revised to update references.
Subpart Q		
250.1703	250.1703	Revised paragraph (b) to have new packers and bridge plug requirements, including API Spec. 11D1. Revised paragraph (e); Redesignated existing paragraph (f) as (g); and added a new paragraph (f) to follow the applicable requirements of subpart G.
250.1704	250.1704	Revised paragraphs (g) and added new paragraph (h) about APMs and EORs.
250.1705	250.731, 250.732	Removed - similar language found in new subpart G.
250.1706(a) through (e)	250.730; 250.733, 250.734, and 250.735	Removed - similar language found in new subpart G.
250.1706(f) through (h)	250.1706(a) through (c)	Revised the section heading; redesignated.
250.1707	250.711, 250.736, 250.737, 250.746	Removed - similar language found in new subpart G.
250.1708	250.739	Removed - similar language found in new subpart G.
250.1709	250.720	Removed - similar language found in new subpart G.
250.1715(a)(3)(iii)(B)	250.1715(a)(3)(iii)(B)	Added the word "casing."
250.1717	250.744	Removed - similar language found in new subpart G.
250.1721(g)	250.744	Removed - similar language found in new subpart G.
250.1721(h)	250.1721(g)	Redesignated and text remains unchanged.

VIII. Procedural Matters

Regulatory Planning and Review (Executive Orders (E.O.) 12866 and 13563)

E.O. 12866 provides that the Office of Information and Regulatory Affairs in the Office of Management and Budget (OMB) will review all significant rules. To determine if this rulemaking is a significant rule, BSEE prepared an economic analysis to assess the anticipated costs and potential benefits of the rulemaking.

Changes to Federal regulations must undergo several types of economic analyses. First, E.O. 12866 and E.O. 13563 direct agencies to assess the costs and benefits of regulatory alternatives and, if regulation is necessary, to select a regulatory approach that maximizes net benefits (including potential economic, environmental, public health, and safety effects; distributive impacts; and equity). Under E.O. 12866, an agency must determine whether a regulatory action is significant and, therefore, subject to the requirements of E.O. 12866, including review by OMB. Section 3(f) of E.O. 12866 defines a ''significant regulatory action'' as any regulatory action that is likely to result in a rule that:

—Has an annual effect on the economy of $100 million or more, or adversely affects in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities (also referred to as ''economically significant'');

—Creates serious inconsistency or otherwise interferes with an action taken or planned by another agency;

—Materially alters the budgetary impacts of entitlement grants, user fees, loan programs, or the rights and obligations of recipients thereof; or

—Raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in E.O. 12866.

BSEE determined that this rule is a significant rulemaking within the definition of E.O. 12866 because the estimated annual costs or benefits would exceed $100 million in at least one year of the 10-year analysis period. Accordingly, OMB has reviewed this regulation.

The following discussion summarizes the economic analysis; for details, please refer to the final RIA, which can be viewed at *www.regulations.gov* (use the keyword/ID ''BSEE–2015–0002'').

1. Need for Regulation

BSEE identified a need to amend the existing BOP and well-control regulations to enhance the safety and environmental protection of offshore oil and gas operations on the OCS. This final rule creates 30 CFR part 250, subpart G—Well Operations and Equipment. This new subpart consolidates equipment and operational requirements that are contained in other subparts of part 250 pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning. The rule also revises existing provisions throughout subparts D, E, F, and Q of part 250 to address concerns raised in the investigations, BSEE's internal reviews, the 2012 BSEE public forum and other input from stakeholders and the public. The rule addresses and implements multiple recommendations resulting from various investigations of the *Deepwater Horizon* incident.[21] The rule also incorporates guidance from several NTLs and revises provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

2. Alternatives

BSEE has considered three regulatory alternatives:

(1) Promulgate the requirements contained in the proposed rule, including decreasing the BOP pressure testing frequency for workover and decommissioning operations from the current requirement of once every 7 days to once every 14 days;

(2) Promulgate the requirements contained within the proposed rule with a change to the required frequency of BOP pressure testing from the existing regulatory requirements (*i.e.,* once every 7 or 14 days depending upon the type of operation) to once every 21 days for all operations; and

(3) Take no regulatory action and continue to rely on existing BOP regulations in combination with permit conditions, DWOPs, operator prudence, and industry standards as applicable to BOP systems.

By taking no regulatory action, BSEE would leave unaddressed most of the concerns and recommendations that were raised regarding the safety of offshore oil and gas operations and the potential for another catastrophic event with consequences similar to those of *Deepwater Horizon*.

Alternative 2 (changing the required frequency of BOP pressure testing to once every 21 days for all operations) was not selected because BSEE lacks critical data on testing frequency and equipment reliability to choose this alternative.

BSEE has elected to move forward with Alternative 1—the final rule—which incorporates recommendations provided prior to the proposed rule by government, industry, academia, and other stakeholders. However, as discussed in detail earlier in this preamble, the final rule does include certain revisions based on BSEE consideration of recommendations contained in public comments on the proposed rule, including incorporation of relevant elements of API Standard 53 and related standards. In addition to addressing concerns and aligning with industry standards, BSEE is advancing several of the more critical well-control capabilities beyond current industry standards applicable to BOP systems based on agency knowledge, experience and technical expertise. The rule will also improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings.

3. Economic Analysis

BSEE's initial economic analysis, for the proposed rule, and final economic analysis evaluated the expected impacts of the rule as compared to the baseline, which includes current industry practices in accordance with existing regulations, DWOPs, and industry standards with which operators already comply.[22] Impacts that exist as part of the baseline were not considered costs or benefits of the rule.

The final analysis covers 10 years (2016 through 2025) to ensure it encompasses the significant costs and benefits likely to result from the rule.[23] We used a 10-year analysis period because of the uncertainty associated with predicting industry's activities and

[21] The DOI JIT report, September 14, 2011, Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout; The National Commission final report, January 11, 2011, Deep Water, The Gulf Oil Disaster and the Future of Offshore Drilling; The Chief Counsel for the National Commission report, February 17, 2011, Macondo The Gulf Oil Disaster; the National Academy of Engineering final report, December 14, 2011, Macondo Well-*Deepwater Horizon* Blowout; May 22, 2012, BSEE Public Offshore Energy Safety Forum.

[22] BSEE considers compliance with permits, DWOPs, and industry standards to be ''self-implementing,'' as addressed in Section E.2 of OMB Circular A–4, ''Regulatory Analysis'' (2003), and thus includes these costs in the baseline for the economic analysis. The industry standards relevant to this rule were developed by committees of industry members and others and subsequently approved by an industry standards development organization (*e.g.,* API).

[23] The initial economic analysis, which accompanied the proposed rule published in April 2015, also used a 10-year analysis period, from 2015 through 2024.

the advancement of technical capabilities beyond 10 years. When summarizing the costs and benefits, we present the estimated annual effects, as well as the 10-year discounted totals using discount rates of 3 and 7 percent, per OMB Circular A–4, ''Regulatory Analysis'' (2003).

We sought to quantify and monetize the costs of the following provisions:

(a) Additional information in the description of well drilling design criteria;

(b) Additional information in the drilling prognosis;

(c) Prohibition of a liner as conductor casing;

(d) Additional capping stack testing requirements;

(e) Additional information in the APM for installed packers;

(f) Additional information in the APM for pulled and reinstalled packers;

(g) Rig movement reporting;

(h) Fitness requirements for MODUs;

(i) Foundation requirements for MODUs;

(j) RTM of well operations for rigs under certain circumstances (*e.g.,* rigs with a subsea BOP);

(k) Additional documentation and verification requirements for BOP systems and system components;

(l) Additional information in the APD, APM, or other submittal for BOP systems and system components;

(m) Submission by the operator of an MIA Report completed by a BAVO; [24]

(n) New surface BOP system requirements;

(o) New subsea BOP system requirements;

(p) New accumulator system requirements;

(q) Chart or digital recorders;

(r) Notification and procedures requirements for testing of surface BOP systems;

(s) Alternating BOP control station function testing;

(t) ROV intervention function testing;

(u) Autoshear, deadman, and EDS function testing on subsea BOPs;

(v) Approval for well-control equipment not covered in Subpart G;

(w) Breakdown and inspection of BOP systems and components;

(x) Additional recordkeeping for RTM data;

(y) Industry familiarization with the new rule; and

(z) BAVO application costs.

BSEE also quantified and monetized the potential benefits of the rule, including time savings, reductions in oil spills, and reductions in fatalities. We estimated the benefits derived from time savings associated with § 250.737 of the rule, which streamlines BOP testing for workover. We also estimated time-savings benefits associated with a change in the required frequency of BOP pressure testing under Alternative 1 and Alternative 2, both of which would reduce the number of required BOP pressure tests per year (by reducing test frequency to once every 14 days and 21 days, respectively). In addition, we estimated the benefits derived from the reduction in oil spills and fatalities using the incident-reducing potential of the rule as a whole.

BSEE received comments from the public on various aspects of the economic analysis of the proposed rule. Some commenters expressed concerns about costs that, to them, appeared to be underestimated or not included as impacts of the proposed rule. BSEE reviewed these comments and any new cost information provided by commenters. BSEE then either revised the analysis as appropriate to reflect this new information, or retained the original cost estimates and provided a justification for doing so. With regard to costs that some commenters thought were missing from the initial economic analysis, BSEE notes that many of these costs are actually for items that are included in the regulatory baseline, and thus are not impacts attributable to the rule. In addition, comments on costs were received in reference to some specific requirements in the proposed rule that have not been retained in the final rule. As a result, many of the comments regarding costs of the proposed rule (including but not limited to the potential costs associated with the proposed accumulator capacity requirements and the proposed mandatory 0.5 ppg safe drilling margin) are no longer applicable to the requirements of the final rule.

Another issue regarding the initial economic analysis for the proposed rule related to requirements on various topics that overlapped with each other. In these cases, a particular cost could be attributed to multiple topics. As a result, some comments identified certain costs as missing in the initial RIA, when, in fact, the initial RIA did account for those costs under a related topic to which the commenter may not have attributed the cost. In other cases, however, BSEE found comments on costs to be quite relevant, and made use of the information in those comments to revise the final economic analysis.

In response to comments expressing concern that the 10-year analysis period is too short, BSEE notes that the uncertainty associated with predicting industry activities, the advancement of technical capabilities, and oil price volatility makes it difficult to predict costs that would accrue to industry for a timeframe much longer than 10 years. BSEE also received comments suggesting that other aspects of the rule should be considered, such as the broader, indirect economic impacts that may occur as a result of the rule. BSEE considered and addressed these comments. More details on the public comments on the economic analysis, and BSEE's responses to the comments are in part VI.B.6 of this document.

According to the analytical findings, the time-savings benefits of the final rule result in benefits greater than the costs of the rule. In other words, based on available data, the rule will be cost-beneficial even when only the benefits resulting from time-savings are considered.

The final rule will result in benefits to society by reducing the probability of incidents involving oil spills. The provisions with the highest costs to industry (such as RTM requirements for well operations and alternating BOP control station function testing) would have the largest impact on reducing spills. Benefits of the rule will result from the avoided costs associated with oil spills related to personal injuries, natural resource damages, lost hydrocarbons, spill containment and cleanup, lost recreational opportunities, and impacts to commercial fishing.

To estimate the potential benefits of the rule associated with reducing the risk of oil spill incidents, we examined historical data from the BSEE oil spill database, which contains information for spills greater than 10 barrels of oil for the GOM and Pacific regions. Based upon an analysis of the BSEE oil spill database during the period 1988 to 2010, BSEE identified LWCs associated with oil spills greater than 10 barrels and used this data within the economic analysis.[25] BSEE used 1988 as the starting year of the analysis because DOI undertook a comprehensive overhaul of its offshore regulatory program in that year, which thus provides the most relevant context for evaluating the current state of risk that now exist in OCS offshore operations. The LWCs that resulted in uncontrolled flow of gas, damage to a rig, and/or harm to personnel (but not oil spills over 10

[24] A verification organization seeking BSEE's approval to become a BAVO is required to submit documentation describing the organization's applicable qualification and experience. (*See* § 250.732(a).)

[25] Source: *http://www.bsee.gov/Inspection-and-Enforcement/Accidents-and-Incidents/Spills/.*

barrels) are not reflected in this analysis.[26]

We reviewed the causes of risk without the rule and how those causes of risk would be affected by the rule. In order not to overstate the potential risk reduction, we assumed a 1 percent risk reduction in the likelihood of all oil spills.[27] We multiplied the expected annual number of spilled barrels of oil (based on the observed average of spilled oil per well) by 1 percent to estimate the expected annual reduction in barrels of oil spilled associated with the rule.

We then multiplied the annual reduction in spilled barrels of oil by the social and private costs of a spilled barrel of oil, which is estimated at $3,658 (in 2014 dollars) per barrel. This estimate was derived from the ''Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012–2017'' (hereafter referred to as the ''BOEM Case Study''),[28] and includes costs associated with natural resource damages, the value of lost hydrocarbons, and spill cleanup and containment.[29] We used a natural resource damage cost of $662 per barrel and a cleanup and containment cost of $2,946 per barrel as estimated for the GOM in the Bureau of Ocean Energy Management (BOEM) Case Study (both values adjusted to 2014 dollars). We assumed a value of lost output per barrel of $50.

In addition to the time-savings and risk reduction benefits, the final rule has other benefits. Due to difficulties in measuring and monetizing these benefits, BSEE does not offer a quantitative assessment of them. BSEE has used a conservative approach (one that seeks to avoid over-estimating the benefits) in the valuation of an oil spill, including only selected costs of such a spill. For example, although the analysis captures the environmental damage associated with a spill, the analysis is limited because it considers only the environmental amenities that researchers could identify and monetize. Therefore, the resulting benefits of avoiding a spill should be considered as a lower bound estimate of the true benefit to society that results from decreasing the risk of oil spills.

Exhibit 1 displays the net benefits of the rule under the assumption that the reduction in the risk of incidents is 1 percent. Although BSEE believes the risk reduction of the rule to be at least 1 percent, and likely higher, there is uncertainty around the level of risk reduction the rule would actually achieve.

EXHIBIT 1: SUMMARY OF NET BENEFITS (AT A 1-PERCENT RISK REDUCTION FROM THE RULE) (Millions of 2014 dollars)[1]

Year		Total Benefits (Alternative 1)	Total Costs	Net Benefits (Alternative 1)
1	**2016**	$152.650	$150.361	$2.289
2-10	**Each year 2017-2025**	$152.650	$82.217	$70.433
Undiscounted 10-year total		**$1,526.497**	**$890.309**	**$636.187**
10-Year Total with 3% discounting		**$1,341.197**	**$790.509**	**$550.688**
10-Year Total with 7% discounting		**$1,147.198**	**$686.023**	**$461.175**
10-year Average		**$152.650**	**$89.031**	**$63.619**
Annualized with 3% discounting		**$157.229**	**$92.672**	**$64.557**
Annualized with 7% discounting		**$163.335**	**$97.674**	**$65.661**

[1] Totals may not add because of rounding.

4. Sensitivity Analysis

This section presents a sensitivity analysis of the potential benefits of the rule that could result from varying the following factors:

a. The level of risk reduction of oil spills achieved by the rule, and

b. The level of risk reduction of fatalities achieved by the rule

Exhibit 2 presents the total 10-year benefits and net benefits under a range of possible annual risk reduction levels for oil spills from 0 to 20 percent. The final rule is expected to have positive net benefits across the full range of risk reduction levels.

[26] Previous MMS data indicate that there were a total of 154 LWCs during well operations on the OCS between 1988 and 2015. These LWCs resulted in 14 fatalities, 55 injuries, damage to facilities and equipment, and the release of hydrocarbons.

[27] Several recent studies have estimated the probabilities of blowout failures under a wide range of circumstances. *See, e.g.,* ''Blowout Preventer (BOP) Failure Event and Maintenance, Inspection and Test (MIT) Data Analysis for the Bureau of Safety and Environmental Enforcement (BSEE).'' American Bureau of Shipping and ABSG Consulting Inc., (under BSEE contract M11PC000027), June 2013; ''Improved Regulatory Oversight Using Real-Time Data Monitoring Technologies in the Wake of Macondo,'' K. Carter, U, of Texas at Austin, 2014, published with E. van Oort and A Barendrecht, Society of Petroleum Engineers, 2014; ''*Deepwater Horizon* Blowout Preventer Failure Analysis Report to the U.S. Chemical Safety and Hazard Investigation Board,'' Engineering Services, LP, 2014. Given this accumulated knowledge of failure likelihoods under various circumstances, and analysis of how those likelihoods would be reduced by the rule, BSEE determined that 1 percent is a reasonable lower-bound of risk reduction that could occur as a result of the rule, although in BSEE's expert opinion, the actual risk reduction from the rule will likely be substantially higher than 1 percent.

[28] U.S. Department of the Interior, BOEM, 2012, Economic Analysis Methodology for the Five Year OCS Oil and Gas Leading Program for 2012–2017. BOEM OCS Study 2012–022.

[29] The BOEM Case Study presents per-barrel costs associated with a catastrophic event. We use this estimate because the BOEM Case Study represents a recent estimate for the costs associated with an oil spill which includes data from the *Deepwater Horizon* incident.

EXHIBIT 2: SUMMARY OF NET BENEFITS UNDER DIFFERENT RISK REDUCTION LEVELS (Millions of 2014 Dollars)

Annual Risk Reduction	Annual Benefits	Total 10-Year Benefits (7% Discounting)	Total 10-Year Benefits (3% Discounting)	Total 10-Year Net Benefits (Undiscounted)	Total 10-Year Net Benefits (7% Discounting)	Total 10-Year Net Benefits (3% Discounting)
0%	$0	$1,127	$1,318	$610	$441	$527
1%	$3	$1,147	$1,341	$636	$461	$551
2%	$5	$1,167	$1,364	$663	$481	$574
3%	$8	$1,187	$1,388	$689	$501	$597
4%	$11	$1,207	$1,411	$716	$521	$621
5%	$13	$1,227	$1,434	$742	$541	$644
6%	$16	$1,247	$1,458	$769	$561	$667
7%	$19	$1,267	$1,481	$795	$581	$690
8%	$21	$1,287	$1,504	$822	$601	$714
9%	$24	$1,307	$1,527	$848	$620	$737
10%	$26	$1,326	$1,551	$875	$640	$760
11%	$29	$1,346	$1,574	$901	$660	$783
12%	$32	$1,366	$1,597	$928	$680	$807
13%	$34	$1,386	$1,621	$954	$700	$830
14%	$37	$1,406	$1,644	$981	$720	$853
15%	$40	$1,426	$1,667	$1,007	$740	$877
16%	$42	$1,446	$1,690	$1,034	$760	$900
17%	$45	$1,466	$1,714	$1,060	$780	$923
18%	$48	$1,486	$1,737	$1,087	$800	$946
19%	$50	$1,506	$1,760	$1,113	$820	$970
20%	$53	$1,526	$1,784	$1,140	$840	$993

In addition to the time-savings and the prevention of oil spills benefits, the rule is anticipated to reduce fatalities among rig workers. The oil and gas extraction industry constitutes a relatively small percentage of the national workforce, but has a fatality rate that is higher than the rate for most industries.

The benefits of occupational risk reduction are usually measured using the *value of a statistical life* (VSL). BSEE used a VSL of $8.7 million to estimate the avoided costs associated with a reduction in the fatality rate. This is the EPA-recommended estimate of $7.9 million updated to 2014 dollars.

Exhibit 3 presents the resulting total 10-year fatality risk reduction benefit across a range of risk reduction values from 0 to 20 percent. The exhibit also presents the undiscounted and discounted 10-year total net benefits when fatality risk reduction is considered in addition to the benefits of the rule included in the analysis presented above (assuming a 1 percent risk reduction in the probability of incidents involving oil spills).[30]

[30] Between 1964 and 2010, there were 27 LWcs resulting in oil spills greater than 10 barrels. Two of these events resulted in fatalities, a 1984 blowout and the 2010 *Deepwater Horizon* incident that resulted 4 and 11 fatalities, respectively. Based on the 47-year period from 1964 to 2010, the average number of fatalities was approximately 0.320 annually. Using a VSL of $8,423,301, the average value of fatalities is $2,691,423 per year. Therefore, each 1 percent reduction in the risk of a fatality results in a risk reduction benefit of $26,914.

EXHIBIT 3: MONETIZED BENEFITS FROM AVERTED FATALITIES w/ NET BENEFITS (Millions of 2014 Dollars)

Fatality Risk Reduction	Fatality Risk Reduction Benefit (Total 10-year)	Net Benefits of Rule Without Fatality Risk Reduction (at a 1-Percent Risk Reduction) (Total 10-year)	Net Benefits of Rule With Fatality Risk Reduction (at a 1-Percent Risk Reduction) (Total 10-year)		
	Undiscounted	Undiscounted	Undiscounted	3% Discounting	7% Discounting
0%	$0.000	$636	$636	$551	$461
1%	$0.278	$636	$636	$551	$461
2%	$0.555	$636	$637	$551	$462
3%	$0.833	$636	$637	$551	$462
4%	$1.110	$636	$637	$552	$462
5%	$1.388	$636	$638	$552	$462
6%	$1.665	$636	$638	$552	$462
7%	$1.943	$636	$638	$552	$463
8%	$2.220	$636	$638	$553	$463
9%	$2.498	$636	$639	$553	$463
10%	$2.775	$636	$639	$553	$463
11%	$3.053	$636	$639	$553	$463
12%	$3.330	$636	$640	$554	$464
13%	$3.608	$636	$640	$554	$464
14%	$3.885	$636	$640	$554	$464
15%	$4.163	$636	$640	$554	$464
16%	$4.440	$636	$641	$555	$465
17%	$4.718	$636	$641	$555	$465
18%	$4.995	$636	$641	$555	$465
19%	$5.273	$636	$641	$555	$465
20%	$5.550	$636	$642	$556	$465

BSEE has concluded that, after considering all of the impacts of the final rule, the societal benefits justify the societal costs. In fact, as previously explained, BSEE estimates that, over the 10-year economic analysis period, the quantifiable benefits of the rule (*i.e.,* $1,147 million with 7 percent discounting) will substantially exceed the quantifiable costs (*i.e.,* $686 million with 7 percent discounting). (See Exhibit 1.)

5. Probabilistic Risk Assessment

The benefits (and costs) of a regulation are based on the difference between the baseline (*i.e.,* status quo) and the state of the world under the regulation. In relation to safety, environmental, and security benefits, one approach to estimating the benefits is based on the amount of risk reduction. In general, risk can be reduced in two distinct ways: By decreasing the probability of the event, and/or by decreasing the consequences of the event. The evaluation of the reduction in risk typically can be performed in either a deterministic or probabilistic approach.

Historically, BSEE has evaluated the reduction of risk based on a deterministic approach. A probabilistic approach, however, could enhance and extend more traditional approaches by: (1) Allowing consideration of a broader set of potential challenges; (2) providing a logical means for prioritizing these challenges based on risk significance; and (3) allowing consideration of a broader set of resources to address these challenges. Probabilistic risk assessments have been used in some cases by certain Federal agencies including the U.S. Nuclear Regulatory Commission, DHS, and the National Aeronautics and Space Administration.

BSEE, however, does not currently collect data that provides a comprehensive basis for a probabilistic risk model. In addition, BSEE is not aware of any current industry-wide efforts to collect data for such a purpose, although BSEE has requested that the Ocean Energy Safety Institute develop a database related to equipment reliability that might provide useful information for the future development of a probabilistic risk assessment.

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) requires agencies to prepare a regulatory flexibility analysis to determine whether a regulation can be expected to have a significant economic impact on a substantial number of small entities. Further, the Small Business Regulatory Enforcement Fairness Act (SBREFA) at (5 U.S.C. 801 *et seq.*) requires that an agency produce compliance guidance for small entities if the rule will have a significant economic impact. For the reasons explained in this section, BSEE believes that this rule will likely have a significant economic impact on a substantial number of small entities and, therefore, a regulatory flexibility analysis is required by the RFA. This Final Regulatory Flexibility Analysis assesses the impact of the rule on small entities, as defined by the applicable Small Business Administration (SBA) size standards.

1. Description of the Reasons for the Actions Being Taken by the Agency

BSEE identified a need to amend the existing Blowout Preventer (BOP) and well-control regulations to enhance the safety and environmental protection of oil and gas operations on the OCS. In particular, BSEE considers this rule necessary to reduce the likelihood of any oil or gas blowout, which can lead to the loss of life, serious injuries, and harm to the environment. As was evidenced by the *Deepwater Horizon* incident (which began with a blowout at the Macondo well on April 20, 2010), blowouts can result in catastrophic consequences.[31] The Federal government and industry conducted multiple investigations to determine the causes of the *Deepwater Horizon* incident; many of these investigations identified BOP performance as a concern. BSEE convened Federal decision-makers and stakeholders from the OCS oil and gas industry, academia, and other entities at a public forum on offshore energy safety on May 22, 2012, to discuss ways to address this concern. The investigations and the forum resulted in a set of recommendations to improve BOP performance. (*see* proposed rule, 80 FR 21508–21511 (April 17, 2015).)

As an agency charged with oversight of offshore operations conducted on the OCS, BSEE seeks to improve safety and mitigate risks associated with such operations. After careful consideration of the various investigations conducted after the *Deepwater Horizon* incident, and of industry's responses to the incident, BSEE has determined that the requirements contained in this rule are necessary to fulfill BSEE's statutory responsibility to regulate offshore oil and gas operations and to enhance the safety of offshore exploration, production, and development. (*See* 43 U.S.C. 1347–1348; 30 CFR 250.101.) BSEE has also determined that the BOP regulations need to be updated to incorporate certain recommendations as discussed in the preambles to the proposed and final rules (*e.g.*, 80 FR 21508–21511), while others are being studied for consideration in future rulemakings. The rule creates a new subpart G in 30 CFR part 250 to consolidate the requirements for drilling, completion, workover, and decommissioning operations. Consolidating these requirements will improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings. The rule also revises existing provisions throughout Subparts D, E, F, and Q to address concerns raised in the investigations, BSEE's internal reviews, the 2012 BSEE public forum, and other input from stakeholders and the public. The rule also incorporates guidance from several NTLs and revises provisions related to drilling, workover, completion, and decommissioning operations to enhance safety and environmental protection.

2. Description and Estimated Number of Small Entities Regulated

Small entities, as defined by the RFA, consist of small businesses, small governmental jurisdictions, or other small organizations. This analysis focuses on impacts to small businesses (hereafter referred to as ''small entities'') because we have not identified any impacts to small governmental jurisdictions or to other small organizations. A small entity is one that is independently owned and operated and which is not dominant in its field of operation.[32] The definition of small business varies from industry to industry in order to properly reflect industry size differences.

The rule will affect operators and holders of Federal oil and gas leases, as well as right-of-way holders, on the OCS. This includes 99 businesses with active operations.[33] Businesses that operate under this rule fall under the SBA's North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells). For these NAICS classifications, a small business is defined as one with fewer than 501 employees. Based on these criteria, 50 (50.51 percent) of the businesses operating on the OCS are considered small, and the rest are considered large businesses. BSEE considers that a rule has an impact on a ''substantial number of small entities'' when the total number of small entities impacted by the rule is equal to or exceeds 10 percent of the relevant universe of small entities. Therefore, BSEE expects that the rule will affect a substantial number of small entities.

BSEE is using the estimated 99 businesses based on activity at the time this economic analysis was developed. The 99 businesses represent the best assessment of the total businesses operating in this arena at the time the economic analysis was developed. BSEE recognizes that this number is a dynamic number and can fluctuate;

[31] For example, any approximation of cost would incorporate catastrophic spills such as the *Deepwater Horizon* incident. The cost to BP of cleanup operations for the *Deepwater Horizon* incident has been estimated at more than $14 billion. In addition to cleanup costs, BP has agreed to pay over $14 billion to Federal, state, and local governments for natural resources damages, economic damage claims, or other expenses in a proposed consent decree and proposed settlement agreement that has been approved by the court. Source: Ramseur, J.L., Hagerty, C.L. 2014. ''Deepwater Horizon Oil Spill: Recent Activities and Ongoing Developments,'' Congressional Research Office. Available at: *http://www.fas.org/sgp/crs/misc/R42942.pdf*. *See* summary of settlement agreement regarding natural resources damages at *www.doi.gov/deepwaterhorizon* and at *http://www.justice.gov/enrd/deepwater-horizon*.

[32] *See* 5 U.S.C. 601.

[33] We used ReferenceUSA, a directory of business information for more than 14 million businesses in all zip codes of the United States, to identify the list of offshore oil and gas operators and their numbers of employees.

however, BSEE determined that this number of businesses was appropriate for this rulemaking.

3. Description and Estimate of Compliance Requirements

BSEE has estimated the incremental costs for small operators, lease holders, and right-of-way holders in the offshore oil and natural gas industry. Costs already incurred as a result of current industry practice in accordance with existing regulations, DWOPs, and API industry standards with which operators already comply were not considered as costs of this rule because they are part of the baseline.[34] All costs are presented in 2014 dollars.

As described in section 5 below, BSEE considered three regulatory alternatives:

(1) Promulgate the requirements contained in the rule, including decreasing the BOP testing frequency for workover and decommissioning operations from the current requirement of once every 7 days to once every 14 days. The following chart identifies the BOP testing changes related to Alternative 1;

BOP PRESSURE TESTING

Operation	Current testing frequency	New testing frequency
Drilling/Completions	Once every 14 days	Once every 14 days.
Workover/Decommissioning	Once every 7 days	Once every 14 days.

(2) Promulgate the requirements contained within the rule with a change to the required frequency of BOP pressure testing from the existing regulatory requirements (*i.e.,* once every 7 or 14 days, depending upon the type of operation) to once every 21 days for all operations. The following chart identifies the BOP testing changes related to Alternative 2;

BOP PRESSURE TESTING

Operation	Current testing frequency	New testing frequency (alternative 1)	Alternative 2 testing frequency
Drilling/Completions	Once every 14 days	Once every 14 days	Once every 21 days.
Workover/Decommissioning	Once every 7 days	Once every 14 days	Once every 21 days.

(3) Take no regulatory action and continue to rely on existing BOP regulations in combination with permit conditions, DWOPs, operator prudence, and industry standards as applicable to BOP systems.

By taking no regulatory action (Alternative 3), BSEE would leave unaddressed most of the concerns and recommendations that were raised regarding the safety of offshore oil and gas operations and the potential for another well control event with consequences similar to those of the *Deepwater Horizon* incident (see n. 9, *supra*).

Alternative 2 (changing the required frequency of BOP pressure testing to once every 21 days for all operations) was not selected because BSEE lacks critical data on testing frequency and equipment reliability to justify such a change at this time.

BSEE has elected to move forward with Alternative 1, the final rule, which incorporates recommendations provided by government, industry, academia, and other stakeholders prior to the proposed rule, as well as recommendations contained in public comments on the proposed rule. The final rule also incorporates elements of API Standard 53 and related standards. In addition to addressing concerns arising from the Deepwater Horizon incident and aligning with industry standards, the final rule advances several of the more critical well-control capabilities beyond current industry standards applicable to BOP systems based upon agency knowledge, experience and technical expertise. The final rule will also improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings.

We have estimated the costs of the following provisions of the final rule:

(a) Additional information in the description of well drilling design criteria;

(b) Additional information in the drilling prognosis;

(c) Prohibition of a liner as conductor casing;

(d) Additional capping stack testing requirements;

(e) Additional information in the APM for installed packers;

(f) Additional information in the APM for pulled and reinstalled packers;

(g) Rig movement reporting;

(h) Fitness requirements for MODUs;

(i) Foundation requirements for MODUs;

(j) Monitoring of well operations with a subsea BOP;

(k) Additional documentation and verification requirements for BOP systems and system components;

(l) Additional information in the APD, APM, or other submittal for BOP systems and system components;

(m) Submission by the operator of an MIA Report completed by a BAVO;[35]

(n) New surface BOP system requirements;

(o) New subsea BOP system requirements;

(p) New accumulator system requirements;

(q) Chart or digital recorders;

(r) Notification and procedures requirements for testing of surface BOP systems;

(s) Alternating BOP control station function testing;

(t) ROV intervention function testing;

(u) Autoshear, deadman, and EDS function testing on subsea BOPs;

(v) Approval for well-control equipment not covered in subpart G;

(w) Breakdown and inspection of BOP system and components;

[34] Industry standards are developed by industry members and technical experts in open meetings based on a consensus process. They contain the baseline requirements that the industry has deemed necessary to operate in a safe and reliable manner and are often incorporated into commercial contracts between operators and contractors.

[35] The approved verification organization will have to submit documentation for approval by BSEE describing the organization's applicable qualification and experience. See discussion on Third-party Verification in the final rule for further information.

(x) Additional RTM-related recordkeeping; and

(y) Industry familiarization with the new rule.

(z) BAVO application costs

These requirements and their associated costs to industry and government are discussed in the sections that follow. (Please note that the descriptions of the rule provisions presented in the RFA seek to mirror the language of the rule; however, only the final regulatory text is legally binding.)

(a) Additional Information in the Description of Well Drilling Design Criteria

As discussed in detail in the preamble to the final rule, § 250.413(g) requires information on safe drilling margins to be included in the description of the well drilling design criteria. Safe drilling margins are an important parameter in avoiding a fracturing of the formation or a compromise of the casing shoe integrity. Either of these factors could lead to erratic pressures and uncontrolled flows (*e.g.,* formation kicks) emanating from a well reservoir during drilling. This information is necessary for BSEE to better review the well drilling design and drilling program. The requirement to include information on the safe drilling margins in the well drilling design criteria results in an annual labor cost of about $300 per entity.[36]

(b) Additional Information in the Drilling Prognosis

Section 250.414 requires industry to provide additional information in the drilling prognosis. New paragraph (j) requires the drilling prognosis to identify the type of wellhead system to be installed with a descriptive schematic, which should include pressure ratings, dimensions, valves, load shoulders, and locking mechanism, if applicable. This information will provide BSEE with data to reference during the approval process and will enable industry and BSEE to confirm that the wellhead system is adequate for the intended use.

The requirement to include additional information in the drilling prognosis will result in increased annual labor costs to industry. BSEE considers the additional information required for the drilling prognosis (submitted as part of the APD) to be readily available. We calculated the annual labor cost for this activity by multiplying the time required to gather and document the information by the average hourly compensation rate of the staff most likely to complete this task. We then multiplied the product of this calculation by the estimated number of wells drilled per year, resulting in an estimated annual labor cost to industry for this documentation requirement of about $7,200.[37] No additional costs to BSEE are expected as a result of this requirement. The requirement to include additional information in the drilling prognosis (submitted as part of the APD) results in an annual labor cost of about $70 per entity.[38]

(c) Prohibition of a Liner as Conductor Casing

Former § 250.421(f) is being revised to no longer allow a liner to be installed as conductor casing. This will ensure that the drive pipe is not exposed to wellbore pressures during drilling in subsequent hole sections.

This provision will result in an annual equipment and labor cost to industry for wells that are currently allowed to use a liner as conductor casing. We multiplied the average cost of the casing joints and wellhead per well by the number of affected wells in order to calculate annual equipment installation costs. To calculate the associated annual labor costs, we multiplied the time required to install the equipment per well by the daily labor cost of rig crew time and by the number of wells on which the equipment must be installed. We then summed the equipment and labor costs to estimate the average annual equipment and labor cost to industry for this requirement of $795,000. No additional costs to BSEE are expected as a result of this requirement. This provision will result in an annual equipment and labor cost of about $8,000 per entity.[39]

(d) Additional Capping Stack Testing Requirements

Section 250.462 addresses source control and containment requirements. New paragraph (e)(1) details requirements for testing of capping stacks. New requirements include the function testing of all critical components on a quarterly basis and the pressure testing of pressure containing critical components on a bi-annual basis. Under the former regulations, there is no testing requirement for capping stacks. These new requirements help ensure that operators are able to contain a subsea blowout.

These new testing requirements will result in new equipment and service costs to industry. We estimated the cost of testing for each capping stack, revised based on industry comments on the proposed rule and initial RIA, and multiplied this cost by the total number of anticipated tests to be performed. These calculations resulted in annual compliance costs to industry associated with these requirements of about $226,000, or $2,300 per entity.[40] No additional costs to BSEE are expected as a result of these requirements.

(e) Additional Information in the APM for Installed Packers

In § 250.518, paragraphs (e) and (f) clarify requirements for installed packers and bridge plugs and require additional information in the APM, including descriptions and calculations for determining production packer setting depth. These new provisions codify existing BSEE policy to ensure consistent permitting. BSEE expects that operators already comply with the design specifications included in this section, because they are based on an established industry standard; *i.e.,* API Spec. 11D1. Thus, the depth setting calculation is the only requirement that imposes a new cost beyond the baseline. The required calculations will be submitted for every well that is completed where tubing is installed.

[36] We estimated that industry staff (a mid-level engineer) will spend one hour per well (at a compensation rate of $89.42 per hour) to include the additional information in the well drilling design criteria. Industry already complies with this new requirement as part of its design practice for most wells drilled. We assumed that this requirement will result in a new cost for all wells drilled per year (320). This resulted in an average annual labor cost to industry of $28,614, or an annual labor cost per entity of $289 (assuming 99 entities).

[37] We assumed that industry staff (a mid-level engineer) will spend 0.25 hours to include the additional information in the drilling prognosis for a well. We multiplied the number of industry staff hours per well by the average hourly compensation rate for a mid-level industry engineer ($89.42) and the average number of wells drilled per year (320) to obtain the average annual labor cost to industry of $7,153.

[38] We estimated that industry staff (a mid-level engineer) will spend 0.25 hours to include the additional information in the drilling prognosis for a well, resulting in an annual cost to industry of $7,153, or $72 per entity.

[39] Based on input provided in submittals to BSEE, we estimated that three wells per year (approximately one percent of drilled wells currently) have a liner as conductor casing. We estimated an average cost of the casing joints and wellhead per well at $65,000. This resulted in an average equipment cost of $195,000. We estimated that industry staff (rig crew) will spend one extra day to install the new equipment on a well, and the average labor cost for a rig crew per day is $200,000. This resulted in an estimated average annual labor cost to industry of $600,000. The annual equipment and labor costs total $795,000 for the industry, or $8,030 per entity.

[40] BSEE estimated that the equipment and service costs of testing for capping stacks will be $14,138 per test, based on industry input. Additionally, we estimated that 4 capping stacks will be tested quarterly (or a total of 16 annual tests performed). This rendered a total annual equipment and service cost to industry of $226,200, or $2,285 per entity.

The requirement to include additional information in the APM will result in a labor cost to industry and BSEE. We based the industry labor cost associated with this new requirement on the time required to add the new descriptions and calculations to an APM and on the number of wells with installed packers for which an APM will be submitted per year. We based the new annual labor cost to BSEE on the time that BSEE will spend reviewing the new information in an APM and on the average hourly compensation rate of the BSEE staff most likely to complete this task. We estimated an average annual labor cost of about $5,800 to industry (or about $60 per entity) and an average annual labor cost of about $4,400 to BSEE.[41]

(f) Additional Information in the APM for Pulled and Reinstalled Packers

In § 250.619, new paragraphs (e) and (f) clarify requirements for pulled and reinstalled packers and bridge plugs and require additional descriptions and calculations in the APM regarding production packer setting depth. These new requirements codify existing BSEE policy to ensure consistent permitting. BSEE expects that operators already comply with the design specifications included in this section, which incorporate an established industry standard (*i.e.,* API Spec 11D1). The depth setting description and calculation is the only requirement that will impose a new cost beyond the baseline. The required calculations will be submitted for every well that is worked over where tubing is pulled and then reinstalled. The requirement to include additional information in the APM will result in a labor cost of about $23,000 to industry (or about $200 per entity) and about $17,000 to BSEE.[42]

(g) Rig Movement Reporting

Section 250.712 lists requirements for reporting movement of rig units to the BSEE District Manager. Revised paragraph (a) extends the rig movement reporting requirements to all rig units conducting operations covered under this subpart, including MODUs, platform rigs, snubbing units, and coiled tubing units. Paragraphs (c) and (e) are new and require notification if a MODU or platform rig is to be warm or cold stacked and when a drilling rig enters OCS waters. Paragraph (f) is revised to clarify that, if the anticipated date for initially moving on or off location changes by more than 24 hours, an updated Movement Notification Report will be required. Currently, movement reports are only required for drilling operations, but the rule requires operators to submit movement reports for other operations as well, including when rigs are stacked or enter OCS waters. These changes will allow BSEE to better anticipate upcoming operations, locate MODUs and platform rigs in case of emergency, and verify rig fitness. The requirement to notify BSEE of rig unit movement will result in annual labor costs to industry of about $4,000 (or about $40 per entity) and to BSEE of about $3,100.[43]

(h) Fitness Requirements for MODUs

Section 250.713(a) adds a requirement that operators provide fitness information for a MODU for well operations. Operators must provide information and data to demonstrate the drilling unit's capability to perform at the new drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap (if relevant) that is necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time the APD or APM is submitted, the District Manager may approve the APD or APM but require operators to collect and report this information during operations. Under this circumstance, the District Manager may revoke the approval of the APD or APM if information collected during operations shows that the drilling unit is not capable of performing at the new location. These costs, in combination with the foundation requirements for MODUs, are discussed at the end of the next section.

(i) Foundation Requirements for MODUs

Section 250.713(b) introduces foundation requirements for MODUs performing well operations. Operators must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the rig unit.[44] If operators provide sufficient site-specific information in the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) submitted to BOEM, operators may reference that information. The regulations state that the District Manager may require operators 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 rig unit or equipment installed on a subsea wellhead. For moored rigs, operators must submit a plan of the rig's anchor patterns approved in the EP, DPP, or DOCD in the APD or APM.

This requirement will result in labor costs to industry and BSEE. To calculate the industry labor cost, we multiplied the time required to record and report the information by the average hourly compensation rate of the industry staff most likely to complete this task and by the number of APMs per year. To calculate the BSEE labor cost, we multiplied the time that BSEE will spend to review the information by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the number of APMs per year. The new requirements under § 250.713 to notify BSEE of rig unit movement and foundation requirement for MODUs will result in labor costs to industry and BSEE, based on the labor required per report and the number of reports per year. We estimated these annual labor costs to be about $208,000 to industry (about $2,100 per entity) and about $158,000 to BSEE.[45]

(j) RTM for Well Operations

Section 250.724 is a new section that establishes requirements for:

(1) RTM of well operations on rigs that have a subsea BOP, floating facilities using surface BOPs, and rigs

[41] We estimated that industry staff (a mid-level engineer) will spend 0.25 hours to include the additional information in the APM for a well, at a compensation rate of $89.42 per hour. We estimated that APMs will be submitted for an average of 260 wells with installed packers per year. We estimated that BSEE staff (a mid-level engineer) will spend 0.25 hours to review the additional information in the APM for a well, at a compensation rate of $67.85.

[42] We estimated that industry staff (a mid-level engineer) will spend 0.25 hours (at $89.42 per hour) to include the additional information in the APM for a well, and that APMs will be submitted for an average of 1,010 wells with pulled and reinstalled packers per year. We estimated that BSEE staff (a mid-level engineer) will spend 0.25 hours (at $67.85 per hour) to review the additional information in the APM for a well.

[43] This is based on the assumption of an average of 60 reports per year, of which 50 require about 0.5 hours to prepare by industry (by a mid-level engineer at a compensation rate of $89.42 per hour), and 10 others requiring about 2 hours to complete. It was estimated that BSEE requires as much time to process and review the reports, by a mid-level BSEE engineer, at a compensation rate of $67.85 per hour.

[44] Soil sampling data is included in the exploration plan and DWOP submissions, and verified in the APD process, under existing regulations.

[45] These estimates were based on the assumption that industry staff (a mid-level engineer) will spend 5 hours on average per report, at a compensation rate of $89.42 per hour, and an average of 466 reports will be provided per year. We estimated that BSEE staff (a mid-level engineer) will spend 5 hours on average to review and process the information, at an average compensation rate of $67.85 per hour.

operating in high pressure and high temperature reservoirs,

(2) Storing RTM data onshore, and

(3) An RTM plan addressing RTM capabilities and procedures.

In order to comply with this section, industry will incur annual equipment and labor costs associated with gathering, recording, transmitting, and storing data (as well as minimal one-time labor costs to develop RTM plan).[46] To calculate the costs associated with these new requirements, we estimated the average equipment and labor cost per day to perform continuous monitoring (based on BSEE's interactions with the industry and review of the equipment involved), and the average amount of time that a rig will engage in well operations per year (and will thus be subject to this monitoring requirement). We assumed that this type of service mostly lends itself to a day rate, and multiplied the cost per day to perform the monitoring by the number of days per year that the rig will be engaged in well operations. We then multiplied the product by the number of rigs that will incur this new cost. This calculation resulted in average annual equipment and labor costs for this monitoring requirement of $40.5 million to industry (or about $409,000 per entity).[47] Since BSEE will not normally receive or review RTM plans, no significant additional costs to BSEE are expected as a result of these requirements.

(k) Additional Documentation and Verification Requirements for BOP Systems and System Components

Section 250.730 lists general requirements for BOP systems and system components and adds new documentation and verification requirements.[48] We estimated an annual labor cost to industry of about $1,800 associated with these submissions and labor costs to BSEE of about $700.[49] We were unable to estimate the cost for a certification entity to meet the requirements of ISO 17011 for quality management systems for BOP stacks.

Section 250.731(c) requires verification by a BAVO of specified aspects of equipment design, equipment tests, shear tests, and pressure integrity tests; all certification documentation must be made available to BSEE. The requirements laid out in § 250.731(c) regarding certification for BOP systems and system components will result in new equipment and service costs to industry. We estimated a one-time cost to industry for equipment and service and multiplied the cost by the number of wells that will incur this new cost. This calculation resulted in one-time equipment and service costs for this certification requirement of $12.8 million to industry.[50]

Section 250.732(c) requires a comprehensive review by a BAVO of BOP and related equipment for use in high temperature and high pressure conditions. The requirements in new § 250.732(c) surrounding a review of BOP systems and system components in HPHT conditions will result in new annual costs to industry. To calculate the costs associated with the required verifications of BOP systems and components by BSEE-approved verification organizations, we estimated the annual cost for performing the verification and multiplied the annual cost by the number of wells that will incur this new cost. This calculation resulted in annual equipment and labor costs for this verification requirement of $500,000 to industry.[51]

In total, all of the annual equipment and labor costs associated with these new documentation and certification requirements are estimated to be $18,005 per entity.

(l) Additional Information in the APD, APM, or Other Submittals for BOP Systems and System Components

Section 250.731 lists the descriptions of BOP systems and system components that must be included in the applicable APD, APM, or other submittal for a well. Revised paragraph (a) requires the submittal to include descriptions of the rated capacities for the fluid-gas separator system, control fluid volumes, control system pressure to achieve a seal of each ram BOP, number of accumulator bottles and bottle banks, and control fluid volume calculations for the accumulator system.

New paragraph (e) requires a listing of the functions with sequences and timing of autoshear, deadman, and EDS for subsea BOPs. Paragraph (b) adds schematic drawing requirements, including labeling for the control system alarms and set points, control stations, and riser cross section. For subsea BOPs, surface BOPs on floating facilities, and BOPs operating under HPHT conditions, new paragraph (f) requires submission of a certification that an MIA Report has been submitted within the past 12 months. New paragraphs (c) and (d) include a change in required certifications; the paragraphs require submission of certification from a BAVO (rather than a ''qualified third-party'')[52] that:

[46] As explained later in part VIII, under Paperwork Reduction Act (PRA) of 1995, we assumed that it will take an estimated 5 burden hours to develop each RTM plan. Based on the assumption that industry staff (a mid-level engineer) will develop these plans, at a compensation rate of $89.42 per hour, the one-time cost of this requirement would be about $447 per plan. Over the 10-year economic analysis period, the average annual cost would be about $44.7 per plan. (We believe that the total costs for small entities could be even smaller since, based on the comments submitted by industry, some operators already have RTM plans that may merely need some adjustment to satisfy the final rule requirements; nonetheless, we have assumed here that all affected small entities would need to develop such plans.) These estimated costs are so small that they are effectively subsumed by the overall costs of complying with the RTM requirements generally.

[47] We estimated that the average costs per day and the average operational days per year will be the same for rigs with subsea BOPs, surface BOPs on floating facilities, and rigs operating in HPHT reservoirs. We estimated that a rig operates for 270 days per year (three operations per year and three months per operation) and that the average cost per day to perform continuous monitoring will be $5,000, including equipment and labor. This estimate is based on the experience of the BSEE regulatory staff, working in conjunction with BSEE engineers who interact with industry on a regular basis and review the equipment. We also estimated that half of the rigs with subsea BOPs already conduct this monitoring. Thus, only half of rigs with subsea BOPs (20 rigs) will incur a new cost to comply with these requirements. Similarly, we estimated that a total of 10 rigs (*i.e.,* 5 floating facilities with a surface BOP and 5 rigs in HPHT reservoirs) will incur a new cost to comply with these requirements. We multiplied the time that the rig is operational per year (270) by the average cost per day ($5,000) to perform monitoring and by the number of affected rigs (30) to obtain an average annual equipment and labor cost to industry of $40,500,000.

[48] Section 250.730(d) requires that quality management systems for the manufacture of BOP stacks be certified by an entity that meets the requirements of International Organization for Standardization (ISO) 17011. Additionally, operators may submit a request for approval of equipment manufactured under quality assurance programs other than API Specification Q1, and BSEE may approve such a request provided the operator submits relevant information about the alternative program. Additionally, new paragraph (d) will result in labor costs to industry associated with submitting requests for alternative programs.

[49] We estimated that a mid-level industry engineer will spend 2 hours to submit a request, at a compensation rate of $89.42 per hour, for each of ten wells during the year. We estimated that a mid-level BSEE engineer will spend 1 hour to process a request, at a compensation rate of $67.85 per hour.

[50] We based this estimate on the assumption that the service costs per well will be $40,000, and 320 wells will incur a new cost to comply with these requirements.

[51] We estimated that the annual costs per well will be $50,000. We estimated that 10 HPHT wells will incur a new cost to comply with these requirements. We multiplied the annual cost of equipment and service by the number of affected wells to obtain an average annual equipment and service cost to industry of $500,000.

[52] BSEE expects that BAVOs will come from qualified third parties used by operators under BSEE's former regulations and industry standards. In addition, the certifications required under new § 250.731(c) and (d) are similar to the verifications required by former § 250.416(e) and (f). Thus, there should not be any incremental costs from these new certification requirements.

(1) Test data demonstrate that the shear ram(s) will shear the drill pipe at the water depth, and

(2) The BOP has been designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well, and

(3) That the accumulator systems have sufficient fluid to function the BOP system without assistance from the charging system.

The requirements to provide additional documentation about the BOP system and system components in the APD, APM, or other submittal will result in labor costs to industry and BSEE. To calculate the industry labor cost associated with these new requirements, we multiplied the estimated time it will take to document the required information in an APD, APM, or other submittal by the average hourly compensation rate of the industry staff most likely to complete this task. We then multiplied the product by the estimated number of wells drilled per year.

Likewise, to calculate the new annual labor cost to BSEE, we multiplied the time that BSEE will spend to process each submittal by the average hourly compensation rate of the BSEE staff most likely to complete this task and by the estimated number of wells drilled per year. These calculations resulted in average annual labor costs for this documentation requirement of about $29,000 (about $300 per entity) to industry and about $22,000 to BSEE.

(m) Submission of an MIA Report by a BAVO

Sections 250.732(d) and (e) include new requirements on the submission of an MIA Report on the BOP stack and systems. New paragraph (d) outlines the requirements for this report, which must be completed by a BAVO and submitted by the operator for operations that require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations. We calculate this annual cost by multiplying the time required to complete the task by the number of submittals per year and by the hourly compensation rate of the industry staff most likely to complete the task. These calculations result in an annual labor cost to industry of about $80,000.

Section 250.731(f) requires a certification stating that this report was submitted to BSEE prior to beginning any operations (to include maintenance and repairs) involving these BOPs. The BAVO report will enhance BSEE's review and permitting process and ensure that BSEE is aware of repairs or other changes to the operating BOPs.

These reporting requirements will result in new capital costs to industry and new labor costs to industry associated with the submission and review of reports. To calculate the capital costs to industry of submitting MIA reports, we multiplied the annual capital cost of submitting the report by the estimated number of wells that will be affected. This calculation resulted in annual capital costs for reporting of $4.8 million to industry. To calculate the industry labor cost, we multiplied the time required to submit a report by the average hourly compensation rate of the industry staff most likely to complete this task and then multiplied this cost by the number of additional reports expected per year. These calculations result in average annual labor costs of about $45,000 to industry and about $11,000 to BSEE. Overall, all of the requirements under this section result in an annual cost per entity of about $50,000.[53]

(n) New Surface BOP Requirements

Section 250.735 includes new requirements for surface BOP stacks. Specifically, new § 250.735(g)(2)(i) requires that remotely-operated locking devices be installed on blind shear rams on surface BOPs. BSEE recognizes that the equipment and labor costs associated with this new requirement will be case-specific (since every BOP stack is unique). In any case, BSEE estimates that this new requirement will create a new one-time equipment cost to industry for the installation of remotely-operated locks. Operators may choose, although they are not required, to use hydraulically operated locks to comply with this requirement. Because we cannot predict how many operators will use hydraulic locks, rather than alternative (and typically less costly) locking devices, we have continued to estimate the cost of this provision based on the cost for installing hydraulic locks, even though that may result in an overestimation of actual costs. We estimate this cost by multiplying the cost per equipment part by the number of rigs with surface BOPs. This results in a one-time cost to industry of $2.50 million, or about $2,500 per entity per year (over a 10-year period).[54]

(o) New Subsea BOP System Requirements

Section 250.734 includes new requirements for subsea BOP systems, based on recommendations from the Deepwater Horizon incident investigations. Revised paragraph (a) requires that BOPs be equipped with dual shear rams and outlines the requirements for the shear rams.

BSEE recognizes that the equipment costs associated with these new subsea BOP system requirements will be case-specific. For example, the costs will depend on the age of the rig and BOP system, the BOP system type, and the size of the rig, among other factors. In order to estimate the cost to industry associated with these new shear ram requirements, we multiplied the estimated cost of compliance per rig by the estimated number of affected rigs. Since API Standard 53 covers the requirements under paragraph (a) for all rigs with the exception of moored rigs, the costs of these requirements, except the costs associated with moored rigs, are included in the baseline. We multiplied the cost of compliance for a moored rig by the number of moored rigs in order to calculate the one-time equipment costs of $50 million for this requirement.[55] This results in an average annual cost of $5 million per year over ten years, or an annual cost of about $51,000 per entity.

(p) New Accumulator System Requirements

Section 250.735(a) lists new requirements for the accumulator system of a BOP. The accumulator system must operate all BOP functions against MASP with at least 200 pounds per square inch remaining on the bottles

[53] We estimated an annual capital cost of $15,000 for each of 320 wells, which resulted in an annual capital cost of $4.8 million. For labor costs, we estimated that industry staff (a mid-level engineer) will spend a half hour to prepare a report for each of 320 wells, at a compensation rate of $89.42. We also estimated that the same staff would spend 5 hours for each of 50 reports per year, and 10 hours for each of 90 reports per year.

[54] Based on industry comments, BSEE has revised the cost estimate for this provision. The cost of installing a hydraulically operated lock is estimated at $50,000. Although the revised final rule only imposes such new costs on surface BOPs with blind shear rams, we chose to multiply this cost by the estimated total number (50) of rigs with surface BOPs with any kind of sealing ram to obtain the one-time cost estimate to industry of $2.5 million.

[55] Although the actual costs for obtaining and installing any new equipment required by this section will vary, as stated above, based on existing technology for centering/shearing and BSEE's discussion with a relevant equipment manufacturer, BSEE believes that the height of the subsea BOP stacks will not need to change significantly. We also estimated that 5 moored rigs will be affected and that the one-time capital compliance costs, including installation costs, associated with these shear ram requirements will be $10,000,000 per rig. To calculate the total one-time capital costs to industry, we multiplied the equipment cost per rig by the number of affected rigs to yield a total cost to industry of $50,000,000.

above the pre-charge pressure without use of the charging system. Revised paragraph (a) details additional accumulator requirements regarding fluid capacity and accumulator regulators. This revision will ensure that the BOP system is capable of operating all critical functions.

The requirement that the accumulator system operate all functions for all BOP systems will result in a total one-time cost to industry of about $2.4 million, or about $2,500 per entity per year over 10 years.[56] Since this work can be planned for and done during routine maintenance or downtime scheduled for other reasons, no incremental rig downtime or daily rig costs are expected.

(q) Chart Recorders

Section 250.737(c), which addresses BOP testing requirements, will introduce a requirement that each test must hold the required pressure for five minutes while using a four-hour chart. This chart will contain sufficient detail to show if a leak occurred during the test.

This testing requirement will result in a one-time equipment and labor cost to industry for those operators that do not already have the required equipment. Some operators will have to purchase the equipment (a chart recorder or digital recorder) to be able to comply with the testing requirement. To calculate the equipment cost, we multiplied the estimated cost of equipment per rig by the estimated total number of rigs that may need it. To calculate the one-time labor cost to industry, we multiplied the time required per rig to install the chart recorder by the average hourly compensation rate of the industry staff most likely to complete this task and by the total number of rigs. This calculation resulted in a one-time cost to industry of about $90,000, or about $90 per entity per year over 10 years.[57]

(r) Notification and Procedure Requirements for Testing of Surface BOP Systems

Section 250.737(d)(2) expands notification and procedural requirements regarding the use of water to test a surface BOP system on the initial test. These expanded notification and procedural requirements will result in increased annual costs to industry of about $5,400 (about $50 per entity) and to BSEE of about $4,100.[58]

(s) Alternating BOP Control Station Function Testing

Section 250.737(d)(5) expands the requirements for function testing BOP control stations. It requires that the operator designate the BOP control stations as primary and secondary and alternate function testing of each station weekly. This testing requirement will result in increased operating costs to industry. To calculate the annual operations costs associated with this requirement, we multiplied the time required to conduct the testing per rig by the daily rig operating cost and by the estimated number of rigs affected per year. Because subsea and surface BOPs have different daily rig operating costs, we performed separate calculations for the costs for subsea and surface BOP rigs. We estimated an increased annual operating cost to industry associated with this provision of $25 million, or an annual operations cost of about $250,000 per entity.[59]

(t) ROV Intervention Function Testing

Section 250.737(d)(4) establishes requirements for testing ROV intervention functions to include testing and verifying the closure of the selected ram(s) on a subsea BOP. This testing requirement will result in an annual operations cost to industry of about $417,000, or about $4,200 per entity.[60]

(u) Autoshear, Deadman, and EDS System Function Testing on Subsea BOPs

Section 250.737(d)(12) expands the requirements for function testing of autoshear, deadman, and EDSs on subsea BOPs. It requires the test procedures submitted for the BSEE District Manager's approval to include schematics of the actual controls and circuitry of the system, the approved schematics of the BOP control system, and a description of how the ROV is used during the operation. It also outlines the requirements for the deadman system test, including a requirement that the testing must indicate the discharge pressure of the subsea accumulator system throughout the test. It requires that the blind shear rams be tested to verify closure. The operator must document the plan to verify closure of the casing shear ram(s), if installed, as well as all test results.

These documentation and testing requirements will result in a one-time equipment cost and increased annual operating costs to industry. The industry will incur a one-time equipment cost to purchase a sensing device to detect the discharge pressure during deadman system testing. We multiplied the average cost per rig of the sensing device by the estimated number of subsea BOP rigs required to comply. We assumed installation costs to be negligible because the sensing device will be installed as part of routine servicing. In order to calculate the annual operations cost, we multiplied the estimated time per subsea BOP rig required to comply with the documentation and testing requirements by the daily operating cost for a subsea BOP rig and by the estimated number of subsea BOP rigs affected per year. These calculations resulted in a one-time equipment cost to industry of $100,000 and an average annual increased operating cost to industry of $5 million, or an annual cost of about $51,000 per entity.[61]

[56] BSEE estimated that the cost of the additional equipment needed to meet the requirements will be $25,000 per rig. It is unknown how many rigs already comply; thus, we made a conservative assumption that all rigs will be affected (90 rigs). We obtained an estimated one-time equipment cost of $2.25 million. For the one-time labor cost to industry, we estimated that three days of industry time will be required per rig to install the new equipment. We estimated that industry staff (a mid-level engineer) will spend 24 hours to install the new equipment on a rig, at a compensation rate of $89.42 per hour. This rendered an estimated one-time labor cost to industry of $193,143. Summing the equipment and labor costs resulted in a total one-time cost to industry of $2,443,143. We divided the one-time equipment and labor cost by the number of entities (99) to obtain a one-time equipment and labor cost per entity of $24,6787.

[57] We estimated that a chart recorder would have an average cost of $2,000 per rig, for each of 45 rigs (half of the 90 rigs in total, with the other half estimated to already have the equipment). This yielded an estimated one-time equipment cost to industry of $90,000. We estimated that industry staff (rig crew) will spend five minutes (0.08 hours) per rig to install the equipment at an average hourly compensation rate of $57.20. This resulted in a total one-time cost to industry of $90,215.

[58] This $54 labor cost per entity reflects our assumptions that a mid-level industry engineer will spend 1 additional hour on a submittal as a result of these expanded requirements and that industry will submit 60 notifications per year.

[59] We estimated that testing would require 0.5 days per rig per year. Because subsea and surface BOP rigs have different daily rig operating costs, we performed separate calculations for the costs for subsea and surface BOP rigs. For subsea BOP rigs, we multiplied the time required to conduct the testing per rig by the daily rig operating cost for subsea BOP rigs ($1 million) and by the number of subsea BOP rigs (40) for an annual cost of $20 million for subsea BOP rigs. For surface BOP rigs, we estimated a daily rig operating cost of $200,000 and the number of surface BOP rigs to be 50, for an annual cost of $5 million for surface BOP rigs. Summing the annual costs for subsea BOP rigs and surface BOP rigs resulted in a total annual increased operating cost to industry associated with this provision of $25 million.

[60] We estimated that it will take five minutes per well to conduct the testing and that 120 wells will be affected (40 subsea BOP rigs with three wells per rig). We considered the time diverted for testing as a fraction of a day (0.003472), and the daily operating cost per rig ($1,000,000) to obtain an average annual operations cost to industry of $416,667, or $4,209 per entity.

[61] BSEE estimated that the cost of the sensing device will be $2,500 per rig. We multiplied the equipment cost by the total number of subsea BOP rigs (40) to obtain the one-time equipment cost to

(v) Approval for Well-Control Equipment not Covered in Subpart G

Section 250.738 describes the required actions for specified situations involving BOP equipment or systems. Paragraphs (b), (i), and (o) include requirements for reports from BAVOs. Reports previously required to be prepared by a ''qualified third-party'' under these sections will be required to be prepared by a BAVO. Paragraph (m) includes a similar change and introduces a requirement that an operator request approval from the BSEE District Manager if the operator plans to use well-control equipment not covered in Subpart G. The operator must submit a report from a BAVO, as well as any other information required by the District Manager. This new approval request requirement will result in annual labor costs to industry and BSEE of about $13,000 and about $10,000, respectively, and annual costs per entity of about $100.[62]

(w) Breakdown and Inspection of the BOP System and Components

Section 250.739(b) introduces a requirement for a complete breakdown and inspection of the BOP and every associated component every 5 years, which may be performed in phased intervals. During this complete breakdown and inspection, a BAVO must document the inspection and any problems encountered. This BAVO report must be available to BSEE upon request. This additional requirement is necessary to ensure that the components on the BOP stack will be regularly inspected. In the past, BSEE has, in some cases, seen components of BOP stacks go more than 10 years without this type of inspection.

This inspection and documentation requirement will result in cost to industry associated with generating reports by BAVOs. To calculate this report cost, we multiplied the estimated report cost per rig by the number of reports completed per rig annually and by the estimated number of rigs in operation per year. Because subsea and surface BOPs differ in structure, they incur different costs to break down and inspect. In order to reflect these differences, we performed separate calculations of the costs for subsea and surface BOP rigs. Assuming staggered inspections, we estimated that, in each year, an average of eight subsea BOP rigs would undergo inspections, thereby enabling all 40 subsea BOP rigs to undergo such inspections over a five-year period. Similarly, we estimated that 10, of a total of 50, surface BOP rigs would undergo inspections each year. This resulted in annual costs to industry of $4.3 million, or about $43,000 per entity.[63]

The proposed rule contained a requirement that operators breakdown the entire BOP system every five years for recertification, without the option to phase or stagger recertification. BSEE received comments that this requirement would cause rigs to be out of service for extended periods of time, at substantial opportunity costs to industry. BSEE revised the requirement in the final rule to allow for staggered inspections over the course of five years. This change eliminates the need for rigs to be brought out of service for extended periods of time.

(x) Additional Recordkeeping for RTM

Sections 250.740(a) and 250.741(b) introduce requirements for additional recordkeeping of RTM data for well operations. These additional requirements will create an annual labor cost of about $1,500 to industry, or about $15 per entity.[64]

(y) Industry Familiarization With New Regulations

When the new regulation takes effect, operators will need to read and interpret the rule. Through this review, operators will familiarize themselves with the structure of the new rule and identify any new provisions relevant to their operations. Operators will evaluate whether any new action must be taken to achieve compliance with the rule. Reviewing the new regulations will require staff time, representing a one-time labor cost of about $20,000 or annual cost of $20 per entity.[65]

(z) BAVO Application Costs

Qualified third-parties currently perform verifications under BSEE's existing regulations and current industry practice that are similar to the certifications and verifications that a BAVO will be required to perform under § 250.732(a) of the final rule. BSEE expects that many of these existing third-party organizations will become BAVOs. To become a BAVO, organizations will need to apply to BSEE and have their applications approved by BSEE. Those that are approved as BAVOs will then be placed on a list for operators to use in finding a BAVO that will enable the operators to obtain the required certifications and verifications.

We estimated the number of BAVO applications to be 15 in the first year (2016), three in the second year (2017), and two per year for each of the remaining eight years (2018 to 2025). We further estimated that organizations would require, on average, about 100 hours of a mid-level engineer's time to complete and submit each application. We also estimated that BSEE would require, on average, about 40 hours of a mid-level engineer's time to review and process each application, except during the first year in which BSEE would require 80 hours per application (since BSEE will need additional time in the first year to develop and begin implementing the approval process). These estimates result in average annual costs to industry of about $30,000 per year (about $300 per entity) and to BSEE of about $13,000 per year, for a total average annual cost of $44,000.[66]

Total Cost Burden for Small Entities

To estimate the cost burden for small entities, BSEE scaled the per-entity costs

industry of $100,000. We estimated that it will take one hour per well to perform the testing and documentation tasks required by this provision, and that each subsea BOP rig will be affected (40 subsea rigs). We multiplied the time diverted for testing in a day 0.125 by the daily operating cost per rig ($1,000,000) and by the estimated number of rigs affected per year to obtain an average annual operations cost to industry of $5 million.

62 These estimates are based on the assumption that industry staff (a mid-level engineer) will spend an average of 0.81 hours per report, at a compensation rate of $89.42 per hour, for approximately 183 reports for year. It was estimated that that BSEE staff (a mid-level engineer) will spend the same amount of time to review and process the report, at a compensation rate of $67.85 per hour.

63 For subsea BOP rigs we estimated that equipment and labor cost will be $350,000 per rig, for each of 8 subsea BOP rigs each year, resulting in an annual cost of $2.8 million. For surface BOP rigs we estimated that equipment and labor cost will be $150,000 per rig, for each of 10 rigs per year, resulting in an annual cost of $1.5 million.

64 This $15 labor cost per entity reflects our assumption that an administrative staff will spend 0.5 hours to submit a report for each of 120 wells (three wells per subsea BOP rig).

65 We assumed that industry staff (a professional engineer, supervisory) will spend two hours to review the new regulation, at an hourly wage rate of $53.00, based on BSEE's Supporting Statement A (BSEE Production Safety Systems). We multiplied this wage rate by the private sector loaded wage factor of 1.43 to account for employee benefits, resulting in a loaded average hourly compensation rate of $75.79. We assumed that an industry staff will review the new regulation at each of the 130 field offices. We multiplied the number of hours per review by the average hourly compensation rate and by the number of field offices, resulting in an estimated one-time labor cost to industry of $19,705. We divided annual labor cost of $1,971 by the number of entities (99) to obtain an average annual one-time labor cost of $20.

66 The total is slightly different due to roundiing, using a compensation rate of $89.42 per hour for industry results in an average annual cost to industry of $30,403; and using a compensation rate of $67.85 for BSEE results in an average annual cost to BSEE of $13,299.

to match the labor and equipment costs that would be faced by a small entity with few wells as opposed to large entities with several wells. Of the 99 entities operating on the OCS, 50 (or 50.51 percent) of them are small entities. In terms of revenue of offshore oil and gas sales, these small entities account for 18.50 percent of the total revenue of all 99 entities. This implies that the average small firm tends to have operations that are about 36.6 percent as large as the operations of an average operator, *e.g.,* having that many fewer wells, rigs, and employees, on average. Therefore, it was estimated that the costs per entity for a small entity would be 36.6 percent the cost per entity for all entities. As a result, the total estimated annual cost of the rule per small entity is about $328,000, in comparison to the average annual cost per entity (for all entities) of about $897,000. BSEE's calculations thus indicate that the total cost burden of this rule will be $3.3 million per affected small entity over 10 years, as presented in Exhibit 1.

Exhibit 2 displays estimates of costs to small entities as a percentage of revenues.[67] In all but the first year of the 10 years in the analysis period, the rule represents a cost of approximately $304,000 per affected small entity. In the first year, costs will be higher at about $556,000 per affected small entity as a result of certain one-time equipment costs, especially the costs of new subsea BOP system requirements.

The costs of the rule as a proportion of small entity revenue range from 0.29 percent in most years to 0.52 percent in the first year. BSEE considers a rule to have a ''significant economic impact'' when the total annual cost associated with the rule for a small entity is equal to or exceeds 1 percent of annual revenue. Thus, the rule is not expected to have a significant economic impact on the participating small operators, lease holders, and pipeline right-of-way holders. Therefore, BSEE has concluded that this rule will not have a significant economic impact on a substantial number of small entities.

[67] We used ReferenceUSA, a directory of business information for more than 14 million, businesses in all zip codes of the United States, for data on estimated annual revenue and number of employees. WE retrieved the ReferenceUSA data in February 2015. Based on these data, the average annual revenue of the small operators is $105,963,674.

EXHIBIT 1: COSTS OF THE RULE PER SMALL ENTITY[1]			
Type of Cost	**Total 10 Year Cost per Small Entity (undiscounted)**	**Average Annual Cost per Small Entity (undiscounted)**	**Percent of Total Cost**
(a) Additional information in the description of well drilling design criteria	$1,059	$106	0.03%
(b) Additional information in the drilling prognosis	$265	$26	0.01%
(c) Prohibition of a liner as conductor casing	$29,410	$2,941	0.90%
(d) Additional capping stack testing requirements	$8,368	$837	0.25%
(e) Additional information in the APM for installed packers	$215	$22	0.01%
(f) Additional information in the APM for pulled and reinstalled packers	$835	$84	0.03%
(g) Rig movement reporting	$149	$15	0.00%
(h) and (i) Information on MODUs	$8,018.86	$802	0.24%
(j) RTM of well operations	$1,498,223	$149,822	45.61%
(k) Additional documentation and certification requirements for BOP systems and system components	$65,914	$6,591	2.01%
(l) Additional information in the APD, APM, or other submittal for BOP systems and system components	$1,059	$106	0.03%
(m) Submission of an MIA Report by a BSEE-approved verification organization	$181,156	$18,116	5.51%
(n) New surface BOP requirements	$9,248	$925	0.28%
(o) New subsea BOP system requirements[2]	$184,966	$18,497	5.63%
(p) New accumulator system requirements	$9,038	$904	0.28%
(q) Chart recorders	$334	$33	0.01%
(r) Use water to test surface BOP system on the initial test	$198	$20	0.01%
(s)Alternating BOP control station function testing	$924,829	$92,483	28.15%
(t) ROV intervention function testing	$15,414	$1,541	0.47%
(u) Autoshear, deadman, and EDS system function testing on subsea BOPs	$185,336	$18,534	5.64%
(v) Approval for well-control equipment not covered in Subpart G	$490	$49	0.01%
(w) Breakdown and inspection of BOP system and components	$159,071	$15,907	4.84%
(x) Record-keeping for RTM	$54	$5	0.00%
(y) Industry familiarization with the new rule	$73	$7	0.00%

(z) BAVO applications	$1,125	$112	0.03%
TOTAL	**$3,284,846**	**$328,485**	**100.00%**

[1] Totals may not add because of rounding.
[2] This is a lower-bound estimate of the costs of this provision.

EXHIBIT 2 ANNUAL COST AND REVENUE PER SMALL ENTITY (Thousands of 2014 Dollars)

Year	2016	2017-2025 (the same in each year)
Annual Industry Cost for Affected Small Entities **a**	$556	$304
Average Annual Revenue for Small Entities[1] **b**	$105,964	$105,964
Cost of the Rule as a Percentage of Annual Revenue c = a ÷ b	0.52%	0.29%

[1] Source: ReferenceUSA data as of February 2015.

4. Identification of All Relevant Federal Rules That May Duplicate, Overlap, or Conflict With the Rule

The rule does not conflict with any relevant Federal rules or duplicate or overlap with any Federal rules in any way that will unnecessarily add cumulative regulatory burdens on small entities without any gain in regulatory benefits.

5. Description of Significant Alternatives to the Rule

BSEE considered three regulatory alternatives:

(1) Promulgate the requirements contained within the rule, including decreasing the BOP testing frequency for workover and decommissioning operations from current 7 day to 14 day testing frequency. The following chart identifies the BOP testing changes related to Alternative 1:

BOP PRESSURE TESTING

Operation	Current testing frequency (days)	Testing frequency (days)
Drilling/Completions	14	14
Workover/Decommissioning	7	14

(2) Promulgate the requirements contained within the rule with a change to the required frequency of BOP pressure testing from the existing regulatory requirements (*i.e.,* 7 or 14 days depending upon the type of operation) to 21 days for all operations. The following chart identifies the BOP testing changes related to Alternative 2:

BOP PRESSURE TESTING

Operation	Current testing frequency (days)	Testing frequency (alternative 1) (days)	Alternative 2 testing frequency (days)
Drilling/Completions	14	14	21
Workover/Decommissioning	7	14	21

(3) Take no regulatory action and continue to rely on existing BOP regulations in combination with permit conditions, DWOPs, operator prudence, and industry standards.

BSEE has elected to move forward with Alternative 1—the final rule—which incorporates recommendations provided by government, industry, academia, and other stakeholders prior to the proposed rule or contained in public comments on the proposed rule. In addition to addressing concerns and aligning with industry standards, BSEE is advancing several of the more critical capabilities beyond current industry standards applicable to BOP systems based on agency knowledge, experience and technical expertise. The rule will also improve efficiency and consistency of the regulations and allow for flexibility in future rulemakings.

Small Business Regulatory Enforcement Fairness Act

The rule is a major rule under the Small Business Regulatory Enforcement Fairness Act, 5 U.S.C. 801 *et seq.* Under that statute, a major rule is one that:

(1) Will have an annual effect on the economy of $100 million or more; or

(2) Will cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or

(3) Will have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

BSEE has determined that this rule is a major rule because it will have an annual effect on the economy of $100 million or more in at least one year of the 10-year period analyzed. The requirements apply to all entities operating on the OCS regardless of company designation as a small business. For more information on costs affecting small businesses, see the *Regulatory Flexibility Act* section above.

Unfunded Mandates Reform Act of 1995 (UMRA)

In accordance with UMRA, BSEE has determined that this rule will not impose an unfunded mandate on State, local, or tribal governments of more than $100 million in a single year and will not have a significant or unique effect on State, local, or tribal governments. BSEE has determined that this rule will impose costs on the private sector of more than $100 million in a single year. Although these costs do not appear to trigger the requirement to prepare a written statement under UMRA, DOI has chosen to prepare such a written statement satisfying the requirements of UMRA. Those requirements are addressed and the required statements are found in the final RIA and final RFA analysis or in the preamble of this final rule.

Specifically, the final RIA, the final RFA analysis, or this document:

1. Identify the provisions of Federal law (OCSLA) under which this rule is being promulgated;

2. Include a quantitative assessment of the anticipated costs to the private sector (*i.e.*, expenditures on labor and equipment) of the final rule; and

3. Include qualitative and quantitative assessments of the anticipated benefits of the final rule.

Since all of the anticipated expenditures by the private sector analyzed in the final RIA and the final RFA analysis would be borne by the offshore oil and gas exploration industry, the final RIA and final RFA analysis satisfy the UMRA requirement to estimate any disproportionate budgetary effects of the proposed rule on a particular segment of the private sector (*i.e.*, the offshore oil and gas industry).

As discussed in the Regulatory Planning and Review section (regarding E.O. 12866 and the RFA), and as explained fully in the final RIA, BSEE considered three regulatory alternatives for dealing with the safety and environmental concerns raised by past and potential future losses of well control. BSEE has decided to move forward with this final rule (Alternative 1) because the other alternatives would not as efficiently or effectively address the safety or environmental concerns raised by various investigations and studies related to the *Deepwater Horizon* incident or achieve the objectives of this final rule.

Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this rule does not have significant takings implications. The 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 rule does not have federalism implications. This 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 rule will not affect that role. A federalism assessment is not required.

Civil Justice Reform (E.O. 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

(1) 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

(2) 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)

The BSEE is committed to regular and meaningful consultation and collaboration with tribes on policy decisions that have tribal implications. Under the criteria in E.O. 13175 and DOI's Policy on Consultation with Indian Tribes (Secretarial Order 3317, Amendment 2, dated December 31, 2013), we have evaluated this final rule and determined that it has no substantial direct effects on federally recognized Indian tribes.

Paperwork Reduction Act (PRA) of 1995

This rule contains a collection of information that was submitted to the Office of Management and Budget (OMB) for review and approval under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). The title of the collection of information for this rule is 30 CFR part 250, subpart G, Well Operations and Equipment. The OMB approved the collection under Control Number 1014–0028, expiration 04/30/2019, 285,111 hours, $102,500 non-hour cost burdens. The information collection concerns BOP system requirements and maintaining well control among others; the information is used in BSEE's efforts to regulate oil and gas operations on the OCS, to protect life and the environment, conserve natural resources, and prevent waste.

Potential respondents comprise Federal OCS oil, gas, and sulfur operators and lessees. The frequency of response varies depending upon the requirement. Responses to this collection of information are mandatory, or are required to obtain or retain a benefit. The information collection (IC) does not include questions of a sensitive nature. BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and DOI's implementing regulations (43 CFR part 2), 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection, and* 30 CFR part 252, *OCS Oil and Gas Information Program*.

As stated in the preamble, BSEE received 172 sets of comments from individual entities (companies, industry organizations, or private citizens), of which 12 comments pertained to IC. The commenters discussed the additional burden and felt, in some cases, that the burden was not necessarily sufficient. Therefore, based on these comments there are changes to the paperwork requirements and/or burdens and these changes are as follows:

Applications for Permit to Drill (APD)—we increased the burden hours (+510 hours);

Applications for Permit to Modify—we increased the burden hours (+2,411 hours);

Also, while reviewing comments on the final rule it became more clear that under § 250.712(a), (b), and (f), we were counting the number of physical rigs on the OCS rather than counting the number of rig movement forms submitted. Therefore, we increased the number of response and burden to accurately reflect the number of forms submitted (+681 responses and +166 hours);

Under § 250.712(c), (e)—we increased the burden hours relating to notifications if rigs are warm or cold stacked (+25 responses and +12 hours);

The burden hours for § 250.713(a), (b)—information on MODUs—we revised the burden for collecting and reporting additional information (+466 responses and +2,330 hours);

Under § 250.724—RTM burden hours were increased (−20 responses and +64,200 hours);

Under § 250.724(c)—we added burden hours for the requirement to develop and implement an RTM plan (+130 responses and +650 hours);

Under § 250.732(a)—we increased burden hours for the requirement to submit a verification and supporting information for BAVO (+2 responses and +675 hours);

The burden hours in §§ 250.740, 250.741, and 250.724(b) for retention of drilling records and RTM data were increased (+95 responses and +35 hours);

During the proposed rule, we inadvertently entered the wrong hour burden under the subtotal for subpart G (Rig. Req. 1,783 hours should have been 1,633 hours); therefore, we have decreased the subtotal (−150 hours);

Also, between the proposed rule and the final rule numerous ICs were submitted to OMB resulting in increases/decreases in OMB approved burdens and responses of various regulatory requirements associated with the proposed rule (+577 responses and +22,797 hours) (**Note:** see *www.reginfo.gov* for all of BSEE's ICs); and

Due to the IC renewals, the number of responses changed, which also affected two revised burdens: subpart B—DWOP (−4 hours) and subpart D—EOR (+40 hours).

This rule affects ICs under 30 CFR part 250, subpart A (1014–0022, expiration 8/31/2017); subpart B (1014–0024, expiration 11/30/2018; renewal for this subpart is currently at OMB for approval); Applications for Permits to Drill (1014–0025, expiration 4/30/17); Applications for Permits to Modify (1014–0026, expiration 5/31/17); subpart D (1014–0018, expiration 10/31/17); subpart E, (1014–0004, expiration 12/31/16); subpart F, (1014–0001, expiration 12/31/16); subpart P, (1014–0006, expiration 12/31/16); and subpart Q, (1014–0010, expiration 10/31/16). Once this final rule becomes effective, the paperwork burdens associated with the various other subparts will be removed from this collection of information (subpart G) and consolidated with the respective IC burdens under their OMB Control Numbers.

This rule also codifies NTL 2013–G01, Global Positioning Systems (GPS) for Mobile Offshore Drilling Units (MODUs) (1014–0013, expiration 11/30/2018 (renewal for this collection is currently at OMB for approval)) into subpart G. Once this final rule becomes effective, the IC for that NTL will be discontinued.

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BURDEN TABLE

[Current regulations are regular font with an asterisk (*); *Italic* font show *revision(s)* of existing requirements; and **bold** text indicates new requirements]

BAVO = BSEE Approved Verification Organization

30 CFR Part 250 Current *Revision* **NEW**	Reporting & Recordkeeping Requirement+	Hour Burden	Average No. of Annual Responses	Annual Burden Hours (rounded)
Subpart A				
107(e)	Produce and submit documents ordered by BSEE to ensure compliance with this part.	Burden covered under various 30 CFR part 250 regulations (depending on the operational requirement(s)).		0
141; 198; **701; 720(a)(2); 721(d); 730(d)(1);** 1612	Request approval to use new or alternative procedures, along with supporting documentation if applicable, including BAST not specifically covered elsewhere in regulatory requirements.	22	1,430 requests	31,460*
142; 198; **702**	Request approval of departure from operating requirements not specifically covered elsewhere in regulatory requirements, along with supporting documentation if applicable.	3.5	405 requests	1,418*
		Subtotal (A)	1,835 responses	32,878 hours*
Subpart B				
287; 291; 292(*p*)	Submit DWOP and accompanying/ supporting information. *Provide detailed information/descriptions pertaining to pipeline free standing hybrid riser (FSHR). Submit documentation for pipeline FSHR certification and have verified by CVA.*	1,140 *4*	11 plans	12,540* *44*
		Subtotal (B)	11 responses	12,540 hours* *44 hours* 12,584 hours

Applications for Permit to Drill (APD)				
410-418; 420(a); 423(c); **428(b), (k);** plus various references in subparts A, D, E, F, **G (701; 702; 713(a), (b), (e), (g); 720(b); 721(g)(4); 724(b); 731; 733(b); 734 (c); 737(a)(3), (b)(2), (b)(3), (d)(2) through (4), (d)(12); 738(f), (m), (n);** H; and P	Apply for permit to drill APD (Form BSEE-0123) that includes any/all supporting documentation /evidence (including, but not limited to, test results, calculations, pressure integrity, kill weight fluids, verifications, certifications, procedures, criteria, qualifications, diverter descriptions*;* **planned safe drilling margin;** rig anchor pattern plats; contingency plan (move off info/**current monitoring**); description of your BOP and its components and schematic drawings; **descriptive schematic (pressure ratings, dimensions, valves, load shoulders;** locking mechanisms**; location of ruptured disks; description of mudline level to displace cement; how operator visually monitors returns; PE certification re changes to casing setting depths; BAVO reports; description of source control and containment capabilities; EDS; pipe variable bore rams; annulus monitoring plan information; any additional information required by District Manager**; etc.) and requests for various approvals required in Subpart D (including §§ *250.414(h); 418(g);* 427, 428, 432, 460, 490(c)) and submitted via the form; upon request, make available to BSEE.	114.98 **4**	408 applications	46,912* **1,632**
420(b)(4); 428; 465(a)(1); **721(g)(4); 731; 734(c)**	Obtain approval to revise your drilling plan [changes to the casing], or change major drilling equipment by submitting a revised Form BSEE-0123, Application for Permit to Drill; **include BAVO certification; any other information required by the District Manager.**	1.34	662 submittals	888*
		Subtotal (APD)	1,070 responses	47,800 hours* **1,632 hours** 49,432 hours
Application for Permit to Modify (APM)				
460; 465; ref in subparts A, D, E *518(f);* F, *619(f)*; **G, 701; 702; 713(a), (b), (e), (g); 720(b); 721(g)(4); 724(b);**	Provide revised plans and the additional supporting information required by the cited regulations [test results; calculations; verifications; certifications, procedures; **descriptions/calculations of production packer setting depth**; **BAVO reports/certifications;** rig anchor pattern plats; contingency plan *(*move off info/**current monitoring**)*;* description of your BOP, its components and schematic drawings; [annulus monitoring plan information]; criteria; qualifications**;** etc.] when you submit an	2.841 **1.5**	2,893 applications	8,219* **4,340**

**731; 733(b); 734(b)(1); 737(d)(2) through (4), (d)(12); 738(f), (m), (n)*;* *H;* P; and Q *1704(g)*	Application for Permit to Modify (APM) (Form BSEE-0124) to BSEE for approval.			
Subparts D, E, F, H, P, Q	Submit Revised APM plans (BSEE-0124). (This burden represents only the filling out of the form).	1	1,551 applications	1,551*
		Subtotal (APM)	4,444 responses	9,770 hours* **4,340 hours** 14,110 hours
		Subpart D		
420(b)(3); 465(a) *(b)(3);* plus various ref in A, D, E, F, **G, 721(g)(8); 744;** P; Q (1704**(h)**);	Submit form BSEE-0125 (End-of-Operations Report (EOR)) and all additional supporting information as required by the cited regulations; *and any additional information required by the District Manager.*	2 *1*	279 submittals	558* *279*
421(b)	Alaska only: Discuss the cement fill level with the District Manager.	1	1 discussion	1*
421(f)	Submit and receive approval if unable to cement 500 ft above previous shoe.	Burden covered under 30 CFR part 250, subpart A (§ 250.141/142) 1014-0022		0
423(c)(2)	Document all your test results and make them available to BSEE upon request.	0.5	300 results	150*
428(c)(3); **428(k); 743(a), (c); 746(e);** ref in subparts A, D, **G**	In the GOM OCS Region, submit drilling activity reports weekly (District Manager may require more frequent submittals) on Forms BSEE-0133 (Well Activity Report (WAR)) and BSEE-0133S (Bore Hole Data) with supporting documentation.	1	4,160 submittals	4,160*
428(c)(3); **428(k); 743(b), (c)** ref in A, D, **G**	In the Pacific and Alaska Regions during drilling operations, submit daily drilling reports on Forms BSEE-0133 (Well Activity Report (WAR)) and BSEE-0133S (Bore Hole Data) with supporting documentation.	1	14 wells x 365 days x 20% year = 1,022	1,022*
428(d)	Submit all remedial actions for review and approval by District Manager (before taking action); and any other requirements of the District Manager.	5	1,000 submittals	5,000*
428(d)	*Submit descriptions of completed immediate actions to District Manager and any other requirements of the District Manager.*	*5*	*564 submittals*	*2,820*

428(d)	*Submit PE certification of any proposed changes to your well program; and any other requirements of the District Manager.*	*4*	*450 submittals*	*1,800*
428(k)	**NEW:** Maintain daily drilling report (cementing requirements).	**0.5**	**75 reports**	**38**
428(k)	**NEW:** If cement returns are not observed, contact the District Manager to obtain approval before continuing with operations.	**1**	**10 requests**	**10**
462(c)	**NEW:** Submit a description of source control and containment capabilities and all supporting information for approval.	**8**	**150 submittals**	**1,200**
462(d)	**NEW:** Request re-evaluation of your source containment capabilities from the District Manager and Regional Supervisor.	**1**	**600 requests**	**600**
462(e)(1)	**NEW:** Notify BSEE 21 days prior to pressure testing; witness by BSEE and BAVO.	**0.5**	**150 notifications**	**75**
			6,762 responses	10,891 hours*
			1,014 responses	*4,899 hours*
			985 responses	**1,923 hours**
		Subtotal (D)	8,761 responses	17,713 hours
	Subpart E			
518(f)	Include in your APM descriptions and calculations of production packer setting depth(s).	Burden covered under 1014-0026.		0
	Subpart F			
619(f)	Include in your APM descriptions and calculations of production packer setting depth(s).	Burden covered under 1014-0026.		0
	Subpart G			
	General Requirements			
701; 720(a); 730(d)(1) (250.141)	Request alternative procedures or equipment from District Manager; along with any supporting documentation/ information required.	Burden cover under 1014-0022.		0
702 (250.142)	Request departures from District Manager; include justification; and submit supporting documentation if applicable.	Burden cover under 1014-0022.		0
	Rig Requirements			
710(a)	Instruct crew members in safety requirements of operations - record dates and times of meetings, *include potential hazards; make available to BSEE.*	0.75	7,512 meetings	5,634*
710(b); 738(p)	Prepare a well-control drill plan for each well, including but not limited to instructions re components of BOP, procedures, crew assignments, established times to complete assignments, etc. Keep/post a copy of the plan on the rig at all times; post on rig floor/bulletin board.	0.5	308 plans	154*

711(b), (c)	Record in the daily report: time, date, and type of drill conducted; time re diverter or BOP components; total time for entire drill.	1	8,320 drills	8,320*
712(a), (b), (f)	Notify BSEE of all rig movements on or off locations.	0.1	20 notices	2*
	Rig movements reported on Rig Movement Notification Report (Form BSEE-0144). Including *MODUs,* platform rigs; snubbing units, *lift boats, wire-line units,* and coiled tubing units 24 hours prior to movement; *if the initial date changes by more than 24 hours, submit updated BSEE-0144.*	0.2	151 forms	30*
		0.2	*832 forms*	*166*
712(c), (e)	**NEW:** Notify District Manager if MODU or platform rig is to be warm or cold stacked on Form BSEE-0144; notify District Manager where the rig is coming from when entering OCS waters.	**0.5**	**50 notifications**	**25**
712(d)	**NEW:** Prior to resuming operations, report to District Manager any construction repairs or modifications that were made to the MODU or rig.	**2**	**10 responses**	**20**
713	Submit MODU information if being used for well operations with your APD/APM.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
713(a), (b)	Collect and report additional information if sufficient information is not available.	5	30 responses	150*
			466 responses	*2,330*
713(b)	Reference to Exploration Plan, Development and Production Plan, and Development Operations Coordination Document (30 CFR part 550, subpart B).	Burden covered under 1010-0151.		0
713(c)(1)	Submit 3rd party review of drilling unit according to 30 CFR part 250, subpart I.	Burden covered under 1014-0011.		0
713(c)(2); (417)(c)(2)	Have a Contingency Plan that addresses design and operating limitations of MODU.	Burden covered under 1014-0025.		0
713(d) 417(d)	Submit current certificate of inspection/ compliance from USCG and classification; submit documentation of operational limitations by a classification society.	Burden covered under 1014-0025.		0
714	NEW: Develop and implement dropped objects plan with supporting documentation/ information; any additional information required by the District Manager; make available to BSEE upon request.	**40**	**40 plans**	**1,600**
715; NTL	GPS for MODUs 1 – Notify BSEE with tracking/locator data access and supporting information; notify BSEE Hurricane Response Team as soon as operator is aware a rig has moved off location.	0.25	1 rig 1 notification	1*
	2 –Install and protect tracking/locator devices – (these are replacement GPS devices or new).	20 devices per year for replacement and/or new x $325.00 = $6,500*.		

	3 – Pay monthly tracking fee for GPS devices already placed on MODUs.	40 rigs x $50/month = ($600/year per 1 rig) = $24,000*.		
	4 – Rent GPS devices and pay monthly tracking fee per MODU.	40 rigs @ $1,800 per year = $72,000*.		
			16,343 responses	14,291 hours*
			1,298 responses	*2,496 hours*
			100 responses	**1,645 hours**
			17,741 responses	18,432 hours
		Subtotal (G – Rig Req.)	$102,500 Non-hour cost burdens*	
Well Operations				
720(a)	**NEW:** Notify and obtain approval from the District Manager when interrupting operations.	**5**	**150 notifications**	**750**
720(a)(2)	Request approval to use alternate procedures/barriers.	Burden covered under 1014-0022.		0
720(b)	Submit with your APD or APM reasons for displacing kill-weight fluid with detailed procedures with relevant information of section.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
721(d), (f), (g)	Submit to the District Manager for approval plans to re-cement, repair, or run additional casing/liner, include PE certification of proposed plans.	0.5	88 requests	44*
721(g)(4)	Submit test procedures and criteria for a successful test with APD/APM; if changes made to procedures, submit changes with revised APD or APM.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
721(g)(5)	Document all your test results; make available to BSEE upon request.	0.75	1,340 results	1,005*
721(g)(6)	Notify District Manager immediately of indication of failed negative pressure test; submit description of corrective action taken; receive approval to retest.	1	14 notifications	14*
721(g)(8); 744(a)	Submit Form BSEE-0125, EOR.	Burden covered under 1014-0018.		0
722	Caliper, pressure test, or evaluate casing; submit evaluation results report *including calculations*; obtain approval before *repairing or installing additional casing;* **PE Certification**; or resuming operations (every 30 days during prolonged drilling).	3	247 reports	741*
722(b)(3)	**NEW:** Perform a pressure test after repairs made/casing installed and report results.	**1**	**300 results**	**300**
723(d)	Request exceptions prior to moving rig(s) or related equipment.	1.5	845 requests	1,268*
724	**NEW:** Transmit real-time monitoring (RTM) data onshore during operations or in HPHT reservoirs; store and monitor by qualified personnel. Provide BSEE access to RTM data storage locations upon request.	**2,160**	**30 rigs**	**64,800**

724(c)	**NEW:** Develop and implement a RTM plan that includes all required data of this section; make available to BSEE upon request.	**5**	**130 plans**	**650**
724(b)	**NEW**: Include in your APD a certification that you have such a plan and meet criteria of this section.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
			2,534 responses	3,072 hours*
			610 responses	**66,500 hours**
		Subtotal (G – Well Op.)	3,144 responses	69,572 hours
	BOP System Requirements			
730(a)(4)	**NEW:** Maintain current set of approved schematic drawings on rig and onshore location; obtain approval to resume operations if modified/changed.	**24**	**10 requests**	**240**
730(c)(1)	**NEW:** Provide written notice within 30 days of discovery/identification of equipment failure.	**2**	**30 reports**	**60**
730(c)(2)	**NEW:** Provide BSEE and manufacturer a copy of analysis report re equipment failure.	**5**	**30 reports**	**150**
730(c)(3)	**NEW:** Document all results and any corrective action re failure analysis. Submit report re design change/modified procedures within 30 days of manufacturer's notification.	**5**	**2 reports**	**10**
730(d)(1)	**NEW:** Request alternate approval from using to API Spec. Q1.	**5**	**1 response**	**5**
731	Submit/resubmit BOP component information in APD/APM and certification that verifies changes or moved off location.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
732(a)	**NEW:** Request and submit for approval all relevant information to become a BAVO.	**100**	**7 applications**	**700**
732(b)	**NEW:** Submit BAVO verification and all supporting documentation related to this section (such as, but not limited to shearing testing, pressure integrity testing, calculations, etc.).	**10**	**150 verifications**	**1,500**
732(c)	**NEW:** Submit verifications, before beginning operations in HPHT environment, that a BAVO conducted detailed reviews of the BOP and related equipment.	**10**	**10 wells**	**100**
732(d), (e)	**NEW:** Submit a BAVO Mechanical Integrity Assessment Report that includes all information from this section; make all documentation available to BSEE upon request.	**10**	**90 reports**	**900**
733(b)(2)	**NEW:** Describe in your APD or APM your annulus monitoring plan.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
734(a)(7)	Demonstrate acoustic control system will	5	1 validation	5*

	function properly in environment and conditions; *submit any additional information requested.*	*1*	*10 submittals*	*10*
734(a)(9); 738(n)	Label all functions on all panels.	1.5	33 panels	50*
734(a)(10)	Develop written procedures for operating the BOP stack, LMRP, and minimum knowledge requirements for personnel authorized to operate/maintain BOP components.	Burden covered under 1014-0018.		0
734(b), (c)	*Before resuming operations, submit a revised APD/APM with BAVO report documenting repairs*; perform a new BOP test upon relatch, etc.; receive approval from the District Manager.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
737(a)(3), (a)(4); (b)(2), (b)(3); (d)(2) through (4), d)(12)	In your APD: submit stump, initial, or pressure tests; and subsea BOP procedures and supporting relevant data/information including, but not limited to, casing string and liner; quick disconnect procedures with your deadman test procedures, etc. Obtain approval of test pressures.	Burden covered under 1014-0025.		0
737(c); 746(a), (b), (c), (d)	Record time, date, and results of all pressure tests, actuations, and inspections of the BOP system, its components, and marine riser in the daily report; onsite rep certify and sign/date reports, etc.; document sequential order of BOP, closing times, auxiliary testing, pressure, and duration of each test.	7.75	4,457 results	34,542*
737(d)(2), (d)(3), (d)(4);	Notify District Manager 72 hours prior to testing; if BSEE unable to witness test, provide results to BSEE within 72 hours after completion; document all ROV test results; make available to BSEE upon request.	0.25	186 notifications	47*
		5.5	1,239 results	6,815*
737(d) (12)	Document all autoshear, *EDS,* and deadman test results; make available to BSEE upon request.	0.5	2,520 submittals	1,260*
		1	*120 responses*	*120*
737(e)	Provide 72 hour advance notice of location of shearing ram tests or inspections.	0.25	136 notices	34*
738; 746(e)	**NEW**/*Revised*: Requires District Manager Approval: (a), (d); 746(e) Report problems, issues, leaks; (b) Put well in a safe condition; (b) Prior to resuming operations for new/repaired/reconfigured BOP (*g) Your well control places demands above its rating pressure;* (j) Two barriers in place prior to BOP removal.	**0.5**	**25 requests**	**13**
		1	**25 requests**	**25**
		1	**25 requests**	**25**
		0.25	200 requests	50*
		1	*15 requests*	*15*
		1	**1 request**	**1**
738(b), (i)	**NEW:** Submit a BAVO report/verification that BOP is fit for service.	**0.5**	**50 submittals**	**25**
738(f)	**NEW:** Notify District Manager of BOP configuration changes.	**0.5**	**15 submittals**	**8**
738(g)	**NEW:** Demonstrate well-control procedures will not place demands above its working	**1**	**15 submittals**	**15**

	pressure.			
738(k)	**NEW:** Contact and obtain for approval prior to latching up BOP stack/re-establishing power.	**1**	**2 requests**	**2**
738(m)	**NEW:** Request approval in your APD or APM to utilize any other well-control equipment.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
738(m)	**NEW:** Request approval to utilize any other well-control equipment; include BAVO report re-equipment design and suitability; any other documentation/information required by District Manager.	**2**	**10 requests**	**20**
738(n)	**NEW:** Include in your APD or APM which pipe/variable bore rams meet the criteria.	Burden covered under 1014-0025 for APD; and 1014-0026 for APM.		0
738(o)	**NEW:** Submit BAVO report re failure of redundant control and confirming no impact to the BOP that makes it unfit; receive approval to continue operations; submit any additional information requested by the District Manager.	**1**	**15 submittals**	**15**
739	Document **how you meet/exceed API Standard 53;** maintain complete records; **track/document all inspection dates**; maintain all records including but not limited to **equipment schematics**, maintenance, inspection, repair, etc., for 2 years or longer if directed on the rig; all **equipment schematics**, maintenance, inspection, repair records are located onshore for service life of equipment; make available to BSEE upon request.	9.75	350 records	3,413*
739(b)	**NEW:** A BAVO report documenting inspection, including problems and how corrected; make reports available to BSEE upon request.	**5**	**21 reports**	**105**
			9,122 responses	46,216 hours*
			145 responses	*145 hours*
			534 responses	**3,919 hours**
		Subtotal (G – BOP SR)	9,801 responses	50,280 hours
	Records and Reporting Requirement			
740; 711(b); 724(b); 738(c); 745; 746	Maintain daily report/records onsite during operations include, but not limited to, **date, time, type of drill**, test results; any information required by the District Manager.	25 min	312 reports	130*
		1	**25 responses**	**25**
740; 741; 724(b)	Retain drilling records for 90 days after drilling complete; retain casing/liner pressure, diverter, BOP tests, **real-time monitoring data** for 2 years after completion; any other information requested by the District Manager.	2.15	3,460 records	7,439*
		0.5	**120 records**	**60**

742; NTL	Submit copies of logs/**charts of electrical, radioactive, sonic,** or other well logging operations.	3	281 logs/ surveys	843*
	Submit copies of directional and vertical-well surveys.	1	281 reports	281*
	Submit copies of velocity profiles and surveys.	1	55 reports	55*
	Record and submit core analyses.	1	150 analyses	150*
743(a), (c)	In the GOM OCS Region, submit Well Activity Reports (WARs) weekly (District Manager may require more frequent submittals) on BSEE-0133 and BSEE-0133S (Open Hole Data Report) with supporting information described in this section; *any additional information required by the District Manager.*	Burden covered under 1014-0018.		0
743(b), (c)	In the Pacific and Alaska OCS Regions during operations, submit WARs daily (BSEE-0133 and BSEE-0133S); with supporting information described in this section; *any additional information required by the District Manager*.	Burden covered under 1014-0018.		0
744	Submit form BSEE-0125, EOR.	Burden covered under 1014-0018.		0
745; NTL	Submit copies of well records; paleontological interpretations; service company reports; and other reports or records of operations to BSEE as requested.	1.5	308 submissions	462*
746	Record the time, date, and results of all casing and liner presser tests.	2	4,160 results	8,320*
746(f)	Retain all records pertaining to pressure tests, actuations, and inspections in daily report etc.; retain all records listed in this section on the rig unit for the duration of operation; after completion, retain all records listed in this section for 2 years on rig unit and at the lessee's field office conveniently available to BSEE; make all the records available upon request.	1.5	1,563 records	2,345*
			10,570 responses	20,025 hours*
			145 responses	**85 hours**
Subtotal (G – Rec. & Rpt. Req.)			10,715 responses	20,110 hours
Subpart P				
1612	Request exception from 30 CFR 250.711 requirements.	Burden covered under 1014-0006.		0

Subpart Q			
1704(g), **(h)**	Submit Forms BSEE-0124 and BSEE-0125; include all supporting documentation/ information.	Burden covered under 1014-0018 for BSEE-0125; and 1014-0026 for BSEE-0124.	0
Current burden		52,691 responses	197,483 hours*
Revised burden		*2,457 responses*	*7,584 hours*
NEW burden		**2,374 responses**	**80,044 hours**
Grand Total		57,522 Responses	285,111 Hours
		$102,500 Non-Hour Cost Burden	

* Indicates burdens are covered under one of the following OMB approved control numbers: 1014-0022, subpart A; 1014-0024, subpart B; 1014-0018, subpart D; 1014-0004, subpart E; 1014-0001, subpart F; 1014-0006, subpart P; 1014-0010, subpart Q; 1014-0013, GPS for MODUs; 1014-0025, APDs; or 1014-0026, APMs.

+ In the future BSEE will be allowing the option of electronic reporting for certain requirements.

BILLING CODE 4310–VH–C

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. The public may comment, at any time, on the accuracy of the IC burden in this rule and may submit any comments to DOI/BSEE; ATTN: Regulations and Standards Branch; VAE–ORP; 45600 Woodland Road, Sterling, VA 20166; or email at *kye.mason@bsee.gov*; (703) 787–1607.

National Environmental Policy Act of 1969 (NEPA)

We prepared a final environmental assessment that concludes that this final rule would not have a significant impact on the quality of the human environment under NEPA. A copy of the Environmental Assessment and Finding of No Significant Impact can be viewed at *www.regulations.gov* (use the keyword/ID BSEE–2015–0002).

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, sec. 515, 114 Stat. 2763, 2763A–153–154).

Effects on the Nation's Energy Supply (E.O. 13211)

This rule is not a significant energy action under the definition in E.O. 13211. Although the rule is a significant regulatory action under E.O. 12866, it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. A Statement of Energy Effects is not required.

List of Subjects in 30 CFR Part 250

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Incorporation by reference, Oil and gas exploration, Outer Continental Shelf—mineral resources, Outer Continental Shelf—rights-of-way, Penalties, Reporting and recordkeeping requirements, Sulfur.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Bureau of Safety and Environmental Enforcement (BSEE) amends 30 CFR part 250 as follows:

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

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

Authority: 30 U.S.C. 1751, 31 U.S.C. 9701, 43 U.S.C. 1334.

Subpart A—General

■ 2. Amend § 250.102 by:

■ a. Revising paragraphs (b)(1) and (11) through (13); and

■ b. Adding paragraph (b)(19).

The revisions and addition read as follows:

§ 250.102 What does this part do?

* * * * *

(b) * * *

TABLE—WHERE TO FIND INFORMATION FOR CONDUCTING OPERATIONS

For information about . . .	Refer to . . .
(1) Applications for permit to drill (APD),	30 CFR 250, subparts D and G.
* * * *	* * *
(11) Oil and gas well-completion operations,	30 CFR 250, subparts E and G.
(12) Oil and gas well-workover operations,	30 CFR 250, subparts F and G.
(13) Decommissioning activities,	30 CFR 250, subparts G and Q.

TABLE—WHERE TO FIND INFORMATION FOR CONDUCTING OPERATIONS—Continued

For information about . . .	Refer to . . .
* * * * * * *	
(19) Well operations and equipment,	30 CFR 250, subpart G.

■ 3. Amend § 250.107 by:

■ a. Removing the word ''and'' from the end of paragraph (a)(1);

■ b. Removing the period from the end of paragraph (a)(2) and adding in its place a semicolon; and

■ c. Adding paragraphs (a)(3) and (4) and (e).

The additions read as follows:

§ 250.107 What must I do to protect health, safety, property, and the environment?

(a) * * *

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

* * * * *

(e) BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

■ 4. In § 250.125, revise the table in paragraph (a) to read as follows:

§ 250.125 Service fees.

(a) * * *

Service—processing of the following:	Fee amount	30 CFR Citation
(1) Suspension of Operations/Suspension of Production (SOO/SOP) Request.	$2,123	§ 250.171(e).
(2) Deepwater Operations Plan (DWOP)	3,599	§ 250.292(q).
(3) Application for Permit to Drill (APD); Form BSEE–0123.	$2,113 *for initial applications only; no fee for revisions.*.	§ 250.410(d); § 250.513(b); § 250.1617(a).
(4) Application for Permit to Modify (APM); Form BSEE–0124.	125	§ 250.465(b); § 250.513(b); § 250.613(b); § 250.1618(a); § 250.1704(g).
(5) New Facility Production Safety System Application for facility with more than 125 components.	$5,426 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); $14,280 additional fee will be charged if BSEE deems it necessary to visit a facility offshore, and $7,426 to visit a facility in a shipyard..	§ 250.802(e).
(6) New Facility Production Safety System Application for facility with 25–125 components.	$1,314 Additional fee of $8,967 will be charged if BSEE deems it necessary to visit a facility offshore, and $5,141 to visit a facility in a shipyard..	§ 250.802(e).
(7) New Facility Production Safety System Application for facility with fewer than 25 components.	652	§ 250.802(e).
(8) Production Safety System Application—Modification with more than 125 components reviewed.	605	§ 250.802(e).
(9) Production Safety System Application—Modification with 25–125 components reviewed.	217	§ 250.802(e).
(10) Production Safety System Application—Modification with fewer than 25 components reviewed.	92	§ 250.802(e).
(11) Platform Application—Installation—Under the Platform Verification Program.	22,734	§ 250.905(l).
(12) Platform Application—Installation—Fixed Structure Under the Platform Approval Program.	3,256	§ 250.905(l).
(13) Platform Application—Installation—Caisson/Well Protector.	1,657	§ 250.905(l)
(14) Platform Application—Modification/Repair	3,884	§ 250.905(l).
(15) New Pipeline Application (Lease Term)	3,541	§ 250.1000(b).
(16) Pipeline Application—Modification (Lease Term).	2,056	§ 250.1000(b).
(17) Pipeline Application—Modification (ROW)	4,169	§ 250.1000(b).
(18) Pipeline Repair Notification	388	§ 250.1008(e).
(19) Pipeline Right-of-Way (ROW) Grant Application.	2,771	§ 250.1015(a).
(20) Pipeline Conversion of Lease Term to ROW.	236	§ 250.1015(a).

Service—processing of the following:	Fee amount	30 CFR Citation
(21) Pipeline ROW Assignment	201	§ 250.1018(b).
(22) 500 Feet From Lease/Unit Line Production Request.	3,892	§ 250.1156(a).
(23) Gas Cap Production Request	4,953	§ 250.1157.
(24) Downhole Commingling Request	5,779	§ 250.1158(a).
(25) Complex Surface Commingling and Measurement Application.	4,056	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(26) Simple Surface Commingling and Measurement Application.	1,371	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(27) Voluntary Unitization Proposal or Unit Expansion.	12,619	§ 250.1303(d).
(28) Unitization Revision	896	§ 250.1303(d).
(29) Application to Remove a Platform or Other Facility.	4,684	§ 250.1727.
(30) Application to Decommission a Pipeline (Lease Term).	1,142	§ 250.1751(a) or § 250.1752(a).
(31) Application to Decommission a Pipeline (ROW).	2,170	§ 250.1751(a) or § 250.1752(a).

* * * * *

■ 5. Amend § 250.198 by:

■ a. Revising paragraphs (h)(51), (63), (68), and (70); and

■ b. Removing the period at the end of paragraph (h)(88) and adding a semicolon in its place; and

■ c. Adding paragraphs (h)(89) through (94).

The revisions and additions read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(h) * * *

(51) API Recommended Practice 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, including Errata June 2009, incorporated by reference at §§ 250.292, 250.733, 250.800, 250.901, and 250.1002;

* * * * *

(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, incorporated by reference at §§ 250.730, 250.735, 250.737, and 250.739;

* * * * *

(68) ANSI/API Specification Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, incorporated by reference at §§ 250.730 and 250.806;

* * * * *

(70) ANSI/API Specification 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004, including Errata 1 (September 2004), Errata 2 (April 2005), Errata 3 (June 2006), Errata 4 (August 2007), Errata 5 (May 2009), Addendum 1 (February 2008), Addenda 2, 3, and 4 (December 2008), incorporated by reference at §§ 250.730, 250.806, and 250.1002;

* * * * *

(89) ANSI/API Specification 11D1, Packers and Bridge Plugs, Second Edition, July 2009, incorporated by reference at §§ 250.518, 250.619, and 250.1703;

(90) ANSI/API Specification 16A, Specification for Drill-through Equipment, Third Edition, June 2004, Reaffirmed August 2010, incorporated by reference at § 250.730;

(91) ANSI/API Specification 16C, Specification for Choke and Kill Systems, First Edition, January 1993, Reaffirmed July 2010; incorporated by reference at § 250.730;

(92) API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, Reaffirmed August 2013, incorporated by reference at § 250.730;

(93) ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011, incorporated by reference at § 250.730; and

(94) ANSI/API Recommended Practice 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed January 2009, incorporated by reference at § 250.734.

* * * * *

■ 6. In § 250.199, revise paragraph (e) to read as follows:

§ 250.199 Paperwork Reduction Act statements—information collection.

* * * * *

(e) BSEE is collecting this information for the reasons given in the following table:

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(1) Subpart A, General (1014–0022), including Forms BSEE–0011, iSEE; BSEE–0132, Evacuation Statistics; BSEE–0143, Facility/Equipment Damage Report; BSEE–1832, Notification of Incidents of Noncompliance.	(i) Determine that activities on the OCS comply with statutory and regulatory requirements; are safe and protect the environment; and result in diligent development and production on OCS leases. (ii) Support the unproved and proved reserve estimation, resource assessment, and fair market value determinations. (iii) Assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.
(2) Subpart B, Plans and Information (1014–0024)	Evaluate Deepwater Operations Plans for compliance with statutory and regulatory requirements
(3) Subpart C, Pollution Prevention and Control (1014–0023)	(i) Evaluate measures to prevent unauthorized discharge of pollutants into the offshore waters.

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
	(ii) Ensure action is taken to control pollution.
(4) Subpart D, Oil and Gas and Drilling Operations (1014–0018), including Forms BSEE–0125, End of Operations Report; BSEE–0133, Well Activity Report; and BSEE–0133S, Open Hole Data Report.	(i) Evaluate the equipment and procedures to be used in drilling operations on the OCS.
	(ii) Ensure that drilling operations meet statutory and regulatory requirements.
(5) Subpart E, Oil and Gas Well-Completion Operations (1014–0004)	(i) Evaluate the equipment and procedures to be used in well-completion operations on the OCS.
	(ii) Ensure that well-completion operations meet statutory and regulatory requirements.
(6) Subpart F, Oil and Gas Well Workover Operations (1014–0001)	(i) Evaluate the equipment and procedures to be used during well-workover operations on the OCS.
	(ii) Ensure that well-workover operations meet statutory and regulatory requirements.
(7) Subpart G, Blowout Preventer Systems (1014–0028), including Form BSEE–0144, Rig Movement Notification Report.	(i) Evaluate the equipment and procedures to be used during well drilling, completion, workover, and abandonment operations on the OCS.
	(ii) Ensure that well operations meet statutory and regulatory requirements.
(8) Subpart H, Oil and Gas Production Safety Systems (1014–0003)	(i) Evaluate the equipment and procedures that will be used during production operations on the OCS.
	(ii) Ensure that production operations meet statutory and regulatory requirements.
(9) Subpart I, Platforms and Structures (1014–0011)	(i) Evaluate the design, fabrication, and installation of platforms on the OCS.
	(ii) Ensure the structural integrity of platforms installed on the OCS.
(10) Subpart J, Pipelines and Pipeline Rights-of-Way (1014–0016), including Form BSEE–0149, Assignment of Federal OCS Pipeline Right-of-Way Grant.	(i) Evaluate the design, installation, and operation of pipelines on the OCS.
	(ii) Ensure that pipeline operations meet statutory and regulatory requirements.
(11) Subpart K, Oil and Gas Production Rates (1014–0019), including Forms BSEE–0126, Well Potential Test Report and BSEE–0128, Semiannual Well Test Report.	(i) Evaluate production rates for hydrocarbons produced on the OCS.
	(ii) Ensure economic maximization of ultimate hydrocarbon recovery.
(12) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1014–0002).	(i) Evaluate the measurement of production, commingling of hydrocarbons, and site security plans.
	(ii) Ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security.
(13) Subpart M, Unitization (1014–0015)	(i) Evaluate the unitization of leases.
	(ii) Ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(14) Subpart N, Remedies and Penalties	(The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4).
(15) Subpart O, Well Control and Production Safety Training (1014–0008)	(i) Evaluate training program curricula for OCS workers, course schedules, and attendance.
	(ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.
(16) Subpart P, Sulfur Operations (1014–0006)	(i) Evaluate sulfur exploration and development operations on the OCS.
	(ii) Ensure that OCS sulfur operations meet statutory and regulatory requirements and will result in diligent development and production of sulfur leases.
(17) Subpart Q, Decommissioning Activities (1014–0010)	Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.
(18) Subpart S, Safety and Environmental Management Systems (1014–0017), including Form BSEE–0131, Performance Measures Data.	(i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel).
	(ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.
(19) Application for Permit to Drill (APD, Revised APD), Form BSEE–0123; and Supplemental APD Information Sheet, Form BSEE–0123S, and all supporting documentation (1014–0025).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling.
	(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(20) Application for Permit to Modify (APM), Form BSEE–0124, and supporting documentation (1014–0026).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

Subpart B—Plans and Information

■ 7. Amend § 250.292 by:
■ a. Removing the word ''and'' from the end of paragraph (o);
■ b. Redesignating paragraph (p) as paragraph (q); and
■ c. Adding new paragraph (p).

The addition reads as follows:

§ 250.292 What must the DWOP contain?

* * * * *

(p) If you propose to use a pipeline free standing hybrid riser (FSHR) on a permanent installation that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section:

(1) A detailed description and drawings of the FSHR, buoy and the tether system;

(2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths;

(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198);

(4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;

(5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (*e.g.*, corrosion) that may negatively impact the riser or tether; and

(6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA required in subpart I of this part; and

* * * * *

Subpart D—Oil and Gas Drilling Operations

■ 8. Revise § 250.400 to read as follows:

§ 250.400 General requirements.

Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

§§ 250.401 through 250.403 [Removed and Reserve]

■ 9. Remove and reserve §§ 250.401 through 250.403.

§ 250.406 [Removed and Reserve]

■ 10. Remove and reserve § 250.406.

■ 11. Revise § 250.411 to read as follows:

§ 250.411 What information must I submit with my application?

In addition to forms BSEE–0123 and BSEE–0123S, you must include the information required in this subpart and subpart G of this part, including the following:

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well,	§ 250.412.
(b) Design criteria used for the proposed well,	§ 250.413.
(c) Drilling prognosis,	§ 250.414.
(d) Casing and cementing programs,	§ 250.415.
(e) Diverter systems descriptions,	§ 250.416.
(f) BOP system descriptions,	§ 250.731.
(g) Requirements for using a MODU, and	§ 250.713.
(h) Additional information.	§ 250.418.

■ 12. In § 250.413, revise paragraph (g) to read as follows:

§ 250.413 What must my description of well drilling design criteria address?

* * * * *

(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, planned safe drilling margin, and casing setting depths in true vertical measurements;

* * * * *

■ 13. Amend § 250.414 by:
■ a. Revising paragraphs (c), (h), and (i); and
■ b. Adding paragraphs (j) and (k).

The revisions and additions read as follows:

§ 250.414 What must my drilling prognosis include?

* * * * *

(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

(1) Your safe drilling margin must also include use of equivalent downhole mud weight that is:

(i) Greater than the estimated pore pressure; and

(ii) Except as provided in paragraph (c)(2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.

(2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling

data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight.

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set well behavior observations.

* * * * *

(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to § 250.460);

(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

(k) Any additional information required by the District Manager needed to clarify or evaluate your drilling prognosis.

■ 14. In § 250.415, revise paragraph (a) to read as follows:

§ 250.415 What must my casing and cementing programs include?

* * * * *

(a) The following well design information:

(1) Hole sizes;

(2) Bit depths (including measured and true vertical depth (TVD));

(3) Casing information, including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and

(4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

* * * * *

■ 15. Revise § 250.416 to read as follows:

§ 250.416 What must I include in the diverter description?

You must include in the diverter description:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the element installed in the diverter housing;

(2) Spool outlet internal diameter(s);

(3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) Valve type, size, working pressure rating, and location.

§ 250.417 [Removed and Reserved]

■ 16. Remove and reserve § 250.417.

■ 17. In § 250.418, revise paragraphs (g) and (h), remove paragraph (i), and redesignate paragraph (j) as paragraph (i) to read as follows:

§ 250.418 What additional information must I submit with my APD?

* * * * *

(g) A request for approval, if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

(h) Certification of your casing and cementing program as required in § 250.420(a)(7); and

* * * * *

■ 18. Amend § 250.420 by:

■ a. Revising the introductory text and paragraph (a)(5);

■ b. Redesignating paragraph (a)(6) as paragraph (a)(7);

■ c. Adding new paragraph (a)(6) and paragraph (b)(4); and

■ d. Revising paragraph (c).

The revisions and additions read as follows:

§ 250.420 What well casing and cementing requirements must I meet?

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G of this part.

(a) * * *

(5) Support unconsolidated sediments;

(6) Provide adequate centralization to ensure proper cementation; and

* * * * *

(b) * * *

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

* * * * *

(c) *Cementing requirements.* (1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations. (If a liner is used refer to § 250.421(f)).

(2) You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

■ 19. In § 250.421, revise paragraphs (b) and (f) to read as follows:

§ 250.421 What are the casing and cementing requirements by type of casing string?

* * * * *

Casing type	Casing requirements	Cementing requirements
* * *	* *	* *
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone.	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.

Casing type	Casing requirements	Cementing requirements
* * * * * * *		
(f) Liners	If you use a liner as 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. You may not use a liner as conductor casing .... A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing. If you have a liner lap and are unable to cement 500 feet above the previous shoe, as provided by paragraphs (d) and (e) of this section, you must submit and receive approval from the District Manager on a case-by-case basis.

■ 20. Revise § 250.423 to read as follows:

§ 250.423 What are the requirements for casing and liner installation?

You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners.

(1) You must submit for approval with your APD, test procedures and criteria for a successful test.

(2) You must document all your test results and make them available to BSEE upon request.

§§ 250.424 through 250.426 [Removed and Reserved]

■ 21. Remove and reserve §§ 250.424 through 250.426.

■ 22. In § 250.427, revise paragraph (b) to read as follows:

§ 250.427 What are the requirements for pressure integrity tests?

* * * * *

(b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

■ 23. Amend § 250.428 by:

■ a. Revising paragraphs (b) through (d); and

■ b. Adding paragraph (k).

The revisions and addition read as follows:

§ 250.428 What must I do in certain cementing and casing situations?

* * * * *

If you encounter the following situation:	Then you must . . .
* * * * * * *	
(b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations,	Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment),	(1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
(d) Inadequate cement job,	Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.

If you encounter the following situation:	Then you must . . .
* * * * * * *	
(k) Plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner,	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

§§ 250.440 through 250.451 [Removed and Reserved]

■ 24. Remove the undesignated center heading ''Blowout Preventer (BOP) System Requirements'' and remove and reserve §§ 250.440 through 250.451.

§ 250.456 [Amended]

■ 25. Amend § 250.456:
■ a. In paragraph (i), by adding the word ''and'' after the semicolon;
■ b. By removing paragraph (j); and
■ c. By redesignating paragraph (k) as paragraph (j).

■ 26. Revise § 250.462 to read as follows:

§ 250.462 What are the source control, containment, and collocated equipment requirements?

For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.

(a) To determine your required source control and containment capabilities you must do the following:

(1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well.

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well. SCCE means the capping stack, cap-and-flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels, which have the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This SCCE, supporting equipment, and collocated equipment must include, but is not limited to, the following:

(1) Subsea containment and capture equipment, including containment domes and capping stacks;

(2) Subsea utility equipment including hydraulic power sources and hydrate control equipment;

(3) Collocated equipment including dispersant injection equipment;

(4) Riser systems;

(5) Remotely operated vehicles (ROVs);

(6) Capture vessels;

(7) Support vessels; and

(8) Storage facilities.

(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE–0123. The description of your containment capabilities must contain the following:

(1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor;

(2) A discussion of the determination required in paragraph (a) of this section; and

(3) Information showing that you have access to and the ability to deploy all equipment required by paragraph (b) of this section.

(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your:

(1) Well design changes; or

(2) Approved source control and containment equipment is out of service.

(e) You must maintain, test, and inspect the source control, containment, and collocated equipment identified in the following table according to these requirements:

Equipment	Requirements, you must:	Additional information
(1) Capping stacks, ...	(i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests),	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and a BSEE-approved verification organization.	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production safety systems used for flow and capture operations,	(i) Meet or exceed the requirements set forth in §§ 250.800 through 250.808, excluding required equipment that would be installed below the wellhead or that is not applicable to the cap and flow system.	
	(ii) Have all equipment unique to containment operations available for inspection at all times.	
(3) Subsea utility equipment,	Have all referenced containment equipment available for inspection at all times.	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.

Equipment	Requirements, you must:	Additional information
(4) Collocated equipment, ...	Have equipment available for inspection at all times	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.

■ 27. In § 250.465, revise paragraph (b)(3) to read as follows:

§ 250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE?

* * * * *

(b) * * *

(3) Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE–0125, as required under § 250.744.

§§ 250.466 through 250.469 [Removed and Reserved]

■ 28. Remove and reserve §§ 250.466 through 250.469.

Subpart E—Oil and Gas Well-Completion Operations

■ 29. Revise § 250.500 to read as follows:

§ 250.500 General requirements.

Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

§§ 250.502 and 250.506 [Removed and Reserved]

■ 30. Remove and reserve §§ 250.502 and 250.506.

■ 31. In § 250.513, revise paragraph (b)(4) to read as follows:

§ 250.513 Approval and reporting of well-completion operations.

* * * * *

(b) * * *

(4) All applicable information required in § 250.731.

* * * * *

§ 250.514 [Amended]

■ 32. In § 250.514, remove paragraph (d).

§§ 250.515 through 250.517 [Removed and Reserved]

■ 33. Remove and reserve §§ 250.515 through 250.517.

■ 34. Amend § 250.518 by:

■ a. Removing paragraph (b);

■ b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

■ c. Adding new paragraph (e) and paragraph (f).

The additions read as follows:

§ 250.518 Tubing and wellhead equipment.

* * * * *

(e) When installed, packers and bridge plugs must meet the following:

(1) All permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

Subpart F—Oil and Gas Well-Workover Operations

■ 35. Revise § 250.600 to read as follows:

§ 250.600 General requirements.

Well-workover operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

§ 250.602 [Removed and Reserved]

■ 36. Remove and reserve § 250.602.

§ 250.606 [Removed and Reserved]

■ 37. Remove and reserve § 250.606.

■ 38. In § 250.613, revise paragraph (b)(3) to read as follows:

§ 250.613 Approval and reporting for well-workover operations.

* * * * *

(b) * * *

(3) All information required in § 250.731.

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§ 250.614 [Amended]

■ 39. In § 250.614, remove paragraph (d).

§ 250.615 [Removed and Reserved]

■ 40. Remove and reserve § 250.615.

■ 41. Amend § 250.616 by:

■ a. Revising the section heading;

■ b. Removing paragraphs (a) through (e); and

■ c. Redesignating paragraphs (f) through (h) as paragraphs (a) through (c).

The revision reads as follows:

§ 250.616 Coiled tubing and snubbing operations.

* * * * *

§§ 250.617 and 250.618 [Removed and Reserved]

■ 42. Remove and reserve §§ 250.617 and 250.618.

■ 43. Amend § 250.619 by:

■ a. Removing paragraph (b);

■ b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

■ c. Adding new paragraph (e) and paragraph (f).

The additions read as follows:

§ 250.619 Tubing and wellhead equipment.

* * * * *

(e) If you pull and reinstall packers and bridge plugs, you must meet the following requirements:

(1) All permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

■ 44. Add subpart G to read as follows:

Subpart G—Well Operations and Equipment

General Requirements

Subpart G—Well Operations and Equipment

General Requirements

§ 250.700 What operations and equipment does this subpart cover?

This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

§ 250.701 May I use alternate procedures or equipment during operations?

You may use alternate procedures or equipment during operations after receiving approval as described in § 250.141. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE–0123) (see § 250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE–0124). Procedures for obtaining approval of alternate procedures or equipment are described in § 250.141.

§ 250.702 May I obtain departures from these requirements?

You may apply for a departure from these requirements as described in § 250.142. Your request must include a justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.

§ 250.703 What must I do to keep wells under control?

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subparts O and S of this part;

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and

(f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

Rig Requirements

§ 250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements.* You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

§ 250.711 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by § 250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and

(3) The total time to complete the entire drill.

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

§ 250.712 What rig unit movements must I report?

(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE–0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 24 hours before:

(1) The arrival of a rig unit on location;

(2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (*e.g.*, coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or

(3) The departure of a rig unit from the location.

(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.

(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager:

(1) Where the MODU or platform rig is coming from;

(2) The location where the MODU or platform rig will be positioned;

(3) Whether the MODU or platform rig will be manned or unmanned; and

(4) If the location for stacking the MODU or platform rig changes.

(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig.

(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE–0144, Rig Movement Notification Report.

§ 250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?

If you plan to use a MODU for well operations, you must provide:

(a) *Fitness requirements.* Information and data to demonstrate the MODU's capability to perform at the proposed location. This information must include the maximum environmental and operational conditions that the MODU is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM, but require you to collect and report this information during operations. Under this circumstance, the District Manager may revoke the approval of the APD or APM if information collected during operations shows that the MODU is not capable of performing at the proposed location.

(b) *Foundation requirements.* Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed bottom-founded MODU. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, or equipment installed on a subsea wellhead. For a moored rig, you must submit a plat of the rig's anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.

(c) *For frontier areas.* (1) If the design of the MODU you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU design. If required, you must obtain a third-party review of your MODU similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM.

(2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (*e.g.*, vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) *Additional documentation.* You must provide the current Certificate of Inspection (for U.S.-flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Dynamically positioned MODU.* If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. At a minimum, your plan must address emergency events caused by storms, currents, station-keeping failures, power failures, and losses of well control. The District Manager may require your plan to include additional events that may require movement of the MODU and other information needed to clarify or further address how the MODU will respond to emergencies or other events.

(f) *Inspection of MODU.* The MODU must be available for inspection by the District Manager before commencing operations and at any time during operations.

(g) *Current monitoring.* For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM:

(1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and

(2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria, such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.

§ 250.714 Do I have to develop a dropped objects plan?

If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:

(a) A description and plot of the path the rig will take while running and pulling the riser;

(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;

(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (*e.g.*, riser or casing) and box (*e.g.*, BOP or tree);

(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and

(e) Any additional information required by the District Manager as appropriate to clarify, update, or evaluate your dropped objects plan.

§ 250.715 Do I need a global positioning system (GPS) for all MODUs?

All MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to and during each hurricane season.

(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the MODU moves from its location during a severe storm.

(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.

(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.

(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.

(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.

(f) You must contact the Regional Office and allow real-time access to the MODU location data. When you contact the Regional Office, provide the following:

(1) Name of the lessee and operator with contact information;

(2) MODU name;

(3) Initial date and time; and

(4) How you will provide GPS real-time access.

Well Operations

§ 250.720 When and how must I secure a well?

(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with § 250.721.

(1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following:

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

(iii) Repair to major rig or well-control equipment; or

(iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling).

(2) The District Manager may approve alternate procedures or barriers, in accordance with § 250.141, if you do not have time to install the required barriers or if special circumstances occur.

(b) Before you displace kill-weight fluid from the wellbore and/or riser, thereby creating an underbalanced state, you must obtain approval from the District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers;

(2) Tests you will conduct to ensure integrity of independent barriers;

(3) BOP procedures you will use while displacing kill-weight fluids; and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

§ 250.721 What are the requirements for pressure testing casing and liners?

(a) You must test each casing string that extends to the wellhead according to the following table:

Casing type	Minimum test pressure
(1) Drive or Structural,	Not required.
(2) Conductor, excluding subsea wellheads,	250 psi.
(3) Surface, Intermediate, and Production,	70 percent of its minimum internal yield.

(b) You must test each drilling liner and liner-top to a pressure at least equal to the anticipated leak-off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.

(c) You must test each production liner and liner-top to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(d) The District Manager may approve or require other casing test pressures as appropriate under the circumstances to ensure casing integrity.

(e) If you plan to produce a well, you must:

(1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before perforating the casing or liner; or

(2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before you drill the open-hole section.

(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

(1) You must perform a negative pressure test on your final casing string

or liner. This test must be conducted after setting your second barrier just above the shoe track, but prior to conducting any completion operations.

(2) You must perform a negative pressure test prior to unlatching the BOP at any point in the well. The negative pressure test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack as appropriate to demonstrate casing or liner integrity.

(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative pressure test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.

(5) You must document all your test results and make them available to BSEE upon request.

(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must:

(i) Correct the problem and immediately notify the appropriate District Manager; and

(ii) Submit a description of the corrective action taken and receive approval from the appropriate District Manager for the retest.

(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.

(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE–0125).

§ 250.722 What are the requirements for prolonged operations in a well?

If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:

(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must:

(1) Evaluate the well casing with a pressure test, caliper tool, or imaging tool. On a case-by-case basis, the District Manager may require a specific method of evaluation of the effects on the well casing of prolonged operations; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used.

(b) If well integrity has deteriorated to a level below minimum safety factors, you must:

(1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes;

(2) Repair the casing or run another casing string; and

(3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in § 250.721.

§ 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;

(b) You must install an emergency shutdown station for the production system near the rig operator's console;

(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a rig unit or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a rig unit between wells on a platform; or

(3) A MODU or lift boat moves within 500 feet of a platform. You may resume production once the MODU or lift boat is in place, secured, and ready to begin operations.

(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment, unless otherwise approved by the District Manager.

(1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation.

(2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system.

(3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.

(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.

§ 250.724 What are the real-time monitoring requirements?

(a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling system on the rig; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After operations, you must preserve and store these data onshore for recordkeeping purposes as required in §§ 250.740 and 250.741. You must provide BSEE with access to your designated real-time monitoring data onshore upon request. You must include in your APD a certification that you have a real-time monitoring plan that meets the criteria in paragraph (c) of this section.

(c) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted onshore during operations, how the data will be labeled and monitored by qualified onshore personnel, and how it will be stored onshore;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data including, if applicable, the location of any onshore data monitoring or data storage facilities;

(4) The qualifications of the onshore personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the onshore monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig and onshore personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring or onshore-offshore communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

Blowout Preventer (BOP) System Requirements

§ 250.730 What are the general requirements for BOP systems and system components?

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system (excluding casing shear) must be capable of closing and sealing the wellbore at all times, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53, and the requirements of this subpart, you must follow the requirements of this subpart.

(2) Those provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems:

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A (all incorporated by reference in § 250.198), and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs.

(4) You must send the reports required in this paragraph to: Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than API Spec. Q1, provided you submit a request to the Chief, Office of Offshore Regulatory Programs for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

§ 250.731 What information must I submit for BOP systems and system components?

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

You must submit:	Including:
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings,	(1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled, including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.
(c) Certification by a BSEE-approved verification organization (BAVO),	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system.
(d) Additional certification by a BAVO, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility,	Verification that: (1) The BOP stack is designed and suitable 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; and (3) The BOP stack will operate in the conditions in which it will be used.
(e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.
(f) Certification stating that the MIA Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	

§ 250.732 What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?

(a) BSEE will maintain a list of BSEE-approved verification organizations (BAVOs) on its public website that you must use to satisfy any provision in this subpart that requires a BAVO certification, verification, report, or review. You must comply with all requirements in this subpart for BAVO certification, verification, or reporting no later than 1 year from the date BSEE publishes a list of BAVOs.

(1) Until such time as you use a BAVO to perform the actions that this subpart requires to be performed by a BAVO, but not after 1 year from the date BSEE publishes a list of BAVOs, you must use an independent third-party meeting the criteria specified in paragraph (a)(2) of this section to prepare certifications, verifications, and reports as required by §§ 250.731(c) and (d), 250.732 (b) and (c), 250.734(b)(1), 250.738(b)(4), and 250.739(b).

(2) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the certifications, verifications, and reports required under paragraph (a)(1) of this section.

(3) For an organization to become a BAVO, it must submit the following information to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

(i) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;

(ii) Technical capabilities;

(iii) Size and type of organization;

(iv) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(v) Ability to perform the verification functions for projects considering current commitments;

(vi) Previous experience with BSEE requirements and procedures; and

(vii) Any additional information that may be relevant to BSEE's review.

(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BAVO and supporting documentation as required by this paragraph to the appropriate

District Manager and Regional Supervisor.

You must submit verification and documentation related to:	That:
(1) Shear testing,	(i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well, no later than April 30, 2018; (ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards; (iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe; (iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism as required in § 250.734(a)(16); (v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and (vi) Includes relevant testing results.
(2) Pressure integrity testing, and	(i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 30 minutes; and (iii) Includes all relevant test results.
(3) Calculations	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BAVO that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BAVO access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

You must submit:	Including:
(1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,	
(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible,	(i) Identification of all reasonable potential modes of failure; and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and	
(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.	For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BAVO. You must submit this report to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166. This report must include:

(1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.

(2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.

(3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.

(4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.

(5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.

(6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP

systems meet recognized engineering practices and any applicable OEM requirements.

(7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.

(8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

(9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.

(10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.

(11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.

(12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.

(13) Verification of written procedures for operating the BOP stack and Lower Marine Riser Package (LMRP) (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

§ 250.733 What are the requirements for a surface BOP stack?

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) For BOPs installed after April 29, 2019, follow the BOP requirements in § 250.734(a)(1).

(2) For risers installed after July 28, 2016, use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored for pressure during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements at § 250.721 for testing the casing or liner.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

§ 250.734 What are the requirements for a subsea BOP system?

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

When operating with a subsea BOP system, you must:	Additional requirements:
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than April 29, 2021. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

When operating with a subsea BOP system, you must:	Additional requirements:
	(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole no later than April 30, 2018; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).
(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity located subsea, 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 capacity must: (i) Operate each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) No later than April 29, 2021, have bottles for the autoshear, and deadman that are dedicated to, but may be shared between, those functions. (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;	The ROV must be capable of opening and closing each shear ram, ram locks, one pipe ram, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing its expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum sealing efficiency. (vi) The control system for the emergency functions must be a fail-safe design once activated.
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions;	You must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels, such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system;	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

When operating with a subsea BOP system, you must:	Additional requirements:
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and (ii) A comprehensive knowledge of BOP hardware and control systems.
(12) Before removing the marine riser, displace the fluid in the riser with seawater;	You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.
(15) Install a gas bleed line with two valves for the annular preventer no later than April 30, 2018;	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, you must install the gas bleed line below the upper annular.
(16) Use a BOP system that has the following mechanisms and capabilities;	(i) A mechanism coupled with each shear ram to position the entire pipe, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism no later than May 1, 2023; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a verification report from a BAVO documenting the repairs and that the BOP is fit for service;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4), including deadman. If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737; and

(3) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

§ 250.735 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

(a) An accumulator system (as specified in API Standard 53, and incorporated by reference in § 250.198) that provides the volume of fluid capacity (as specified in API Standard 53, Annex C) necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate the BOP functions as defined in API Standard 53, without assistance from a charging system, and still have a minimum pressure of 200 psi remaining on the bottles above the pre-charge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram;

(f) A fill-up line above the uppermost BOP;

(g) Locking devices for all BOP sealing rams (i.e., blind shear rams, pipe rams and variable bore rams), as follows:

(1) For subsea BOPs, hydraulic locking devices must be installed on all sealing rams;

(2) For surface BOPs:

(i) Remotely-operated locking devices must be installed on blind shear rams no later than April 29, 2019;

(ii) Manual or remotely-operated locking devices must be installed on pipe rams and variable bore rams; and

(h) A wellhead assembly with a RWP that exceeds the maximum anticipated wellhead pressure.

§ 250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a RWP at least as great as the RWP of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a RWP at least as great as the RWP of the ram BOPs.

(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in § 250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(4) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(6) All required manual and remote-controlled kelly-type valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

§ 250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) *Pressure test frequency.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) The District Manager may require more frequent testing if conditions or your BOP performance warrant.

(b) *Pressure test procedures.* When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.

You must conduct a . . .	According to the following procedures . . .
(1) Low-pressure test	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components.	The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.	The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(d) *Additional test requirements.* You must meet the following additional BOP testing requirements:

You must . . .	Additional requirements . . .
(1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).	If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.

You must . . .	Additional requirements . . .
(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system.	(i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the initial test results to the appropriate District Manager within 72 hours after completion of the tests.
(3) Stump test a subsea BOP system before installation	(i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow paragraphs (b) and (c) of this section.
(4) Perform an initial subsea BOP test	(i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to paragraphs (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. (vi) You must pressure test the selected rams according to paragraphs (b) and (c) of this section.
(5) Alternate testing pods between control stations	(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly; (B) The control station used for the pressure test must be alternated between pressure tests; and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing and 14 day pressure testing. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests and monthly thereafter.
(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	
(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53.	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	
(10) Function test shear ram(s) BOPs every 14 days.	
(11) Actuate safety valves assembled with proper casing connections before running casing.	

You must . . .	Additional requirements . . .
(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.	(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event. (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures. (vi) You must pressure test the blind shear ram(s) according to paragraphs (b) and (c) of this section. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the District Manager at least 72 hours in advance, to ensure that a BSEE representative will have access to the location to witness any testing.

§ 250.738 What must I do in certain situations involving BOP equipment or systems?

The table in this section describes actions that you must take when certain situations occur with BOP systems.

If you encounter the following situation:	Then you must . . .
(a) BOP equipment does not hold the required pressure during a test;	Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, on the daily report as required in § 250.746.
(b) Need to repair, replace, or reconfigure a surface or subsea BOP system;	(1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. (4) You must submit a report from a BAVO to the District Manager certifying that the BOP is fit for service.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;	Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered string;	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Test the affected connections before running casing to the RWP or MASP plus 500 psi. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure;	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers and test(s).

If you encounter the following situation:	Then you must . . .
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by: (1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation; (2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or (3) Some combination of paragraphs (l)(1) and (2) of this section.
(m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BAVO on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BAVO that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

§ 250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of BOP stack equipment beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. A BAVO is required to be present during each inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This complete breakdown and inspection must be performed every 5 years from the following applicable dates, whichever is later:

(1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system;

(2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or

(3) The date of the last 5 year inspection for the component.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, are trained in accordance with applicable training requirements in subpart S of this part, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in this subpart.

(e) You must make all records available to BSEE upon request. You must ensure that the rig unit owner maintains the BOP maintenance, inspection, and repair records on the rig unit for 2 years from the date the records are created or for a longer period if directed by BSEE. You must ensure that all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment.

Records and Reporting

§ 250.740 What records must I keep?

You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following:

(a) Well operations, all testing conducted, and any real-time monitoring data as required by § 250.724;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager as appropriate to ensure compliance with the requirements of this section and to enable BSEE to determine that the well operations are consistent with conservation of natural resources and protection of safety and the environment on the OCS.

§ 250.741 How long must I keep records?

You must keep records for the time periods shown in the following table.

You must keep records relating to . . .	Until . . .
(a) Drilling;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of operations.
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.

§ 250.742 What well records am I required to submit?

You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.

§ 250.743 What are the well activity reporting requirements?

(a) For operations in the BSEE Gulf of Mexico (GOM) OCS Region, you must submit Form BSEE–0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE–0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE–0133, WAR, to the District Manager on a daily basis.

(c) The WAR must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information concerning well activities required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

§ 250.744 What are the end of operation reporting requirements?

(a) Within 30 days after completing operations, except routine operations as defined in § 250.601, you must submit Form BSEE–0125, End of Operations Report (EOR), to the District Manager. The EOR must include: a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager regarding the end of well operations. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The well status date is subject to the following:

(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and

(2) For subsea well operations, the operations end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.

(b) You must submit public information copies of Form BSEE–0125 according to § 250.186(b).

§ 250.745 What other well records could I be required to submit?

The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:

(a) Well records as specified in § 250.740;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

§ 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in § 250.740. In addition, you must:

(a) Record test pressures on pressure charts or digital recorders;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts or digital recordings and daily reports as correct;

(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing must be documented in the WAR. If any problems that cannot be resolved promptly are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the rig unit for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the rig unit. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

Subpart P—Sulphur Operations

■ 45. Revise § 250.1612 to read as follows:

§ 250.1612 Well-control drills.

Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 or as approved by the District Manager.

Subpart Q—Decommissioning Activities

■ 46. Amend § 250.1703 by:

■ a. Revising paragraphs (b) and (e);

■ b. Redesignating paragraph (f) as paragraph (g); and

■ c. Adding new paragraph (f).

The revisions and addition read as follows:

§ 250.1703 What are the general requirements for decommissioning?

* * * * *

(b) Permanently plug all wells. Permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

* * * * *

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;

(f) Follow all applicable requirements of subpart G of this part; and

* * * * *

■ 47. Amend § 250.1704 by:

■ a. Revising paragraph (g);

■ b. Redesignating paragraphs (h) and (i) as paragraphs (i) and (j); and

■ c. Adding new paragraph (h).

The revision and addition read as follows:

§ 250.1704 When must I submit decommissioning applications and reports?

* * * * *

Decommissioning applications and reports	When to submit	Instructions
* *	* *	* * *
(g) Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;	(1) Before you temporarily abandon or permanently plug a well or zone,	(i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.
	(2) Before you install a subsea protective device,	Refer to § 250.1722(a).
	(3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device,	Refer to § 250.1723.
(h) Form BSEE–0125, End of Operations Report (EOR);	(1) Within 30 days after you complete a protective device trawl test,	Include information required under § 250.1722(d).
	(2) Within 30 days after you complete site clearance verification activities,	Include information required under § 250.1743(a).

* * * * * * *

§ 250.1705 [Removed and Reserved]

■ 48. Remove and reserve § 250.1705.

■ 49. Amend § 250.1706 by:

■ a. Revising the section heading;

■ b. Removing paragraphs (a) through (e); and

■ c. Redesignating paragraphs (f) through (h) as paragraphs (a) through (c).

The revision reads as follows:

§ 250.1706 Coiled tubing and snubbing operations.

* * * * *

§§ 250.1707 through 250.1709 [Removed and Reserved]

■ 50. Remove and reserve §§ 250.1707 through 250.1709.

■ 51. In § 250.1715, revise paragraph (a)(3)(iii)(B) to read as follows:

§ 250.1715 How must I permanently plug a well?

(a) * * *

PERMANENT WELL PLUGGING REQUIREMENTS

If you have . . .	Then you must use . . .
* * * * *	
(3) * * *.	(iii) * * * (B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;
* * * * *	

* * * * *

§ 250.1717 [Removed and Reserved]

■ 52. Remove and reserve § 250.1717.

§ 250.1721 [Amended]

■ 53. Amend § 250.1721 by removing paragraph (g) and redesignating paragraph (h) as paragraph (g).

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