DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID: BSEE–2012–0005; 16XE1700DX EX1SF0000.DAQ000 EEEE500000]

RIN 1014–AA10

Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Oil and Gas Production Safety Systems

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE), Interior.

ACTION: Final rule.

SUMMARY: The Bureau of Safety and Environmental Enforcement (BSEE) is amending and updating the regulations regarding oil and natural gas production safety on the Outer Continental Shelf (OCS) by addressing issues such as: Safety and pollution prevention equipment design and maintenance, production safety systems, subsurface safety devices, and safety device testing. The rule differentiates the requirements for operating dry tree and subsea tree production systems and divides the current BSEE regulations regarding oil and gas production safety systems into multiple sections to make the regulations easier to read and understand. The changes in this rule are necessary to improve human safety, environmental protection, and regulatory oversight of critical equipment involving production safety systems.

DATES: This rule becomes effective on November 7, 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 II.E of this document.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of November 7, 2016.

FOR FURTHER INFORMATION CONTACT: Amy White, BSEE, Office of Offshore Regulatory Programs, Regulations Development Section, at 571–230–2475 or at *regs@bsee.gov*.

SUPPLEMENTARY INFORMATION:

Executive Summary

This rule amends and updates BSEE's regulations for oil and gas production safety systems. The regulations (30 CFR part 250, subpart H) have not, until now, undergone a major revision since they were first published in 1988. Since that time, much of the oil and gas production on the OCS has moved into deeper waters and the regulations have not kept pace with the technological advancements.

These regulations address issues such as production safety systems, subsurface safety devices, safety device testing, and production processing systems and areas. These systems play a critical role in protecting workers and the environment. In this final rule, BSEE has made the following changes to subpart H:

- Restructured subpart H to have shorter, easier-to-read sections and clearer, more descriptive headings.
- Updated and improved safety and pollution prevention equipment (SPPE) design, maintenance, and repair requirements in order to increase the overall level of certainty that this equipment will perform as intended, including in emergency situations.
- Expanded the regulations to differentiate the requirements for operating dry tree and subsea tree production systems on the OCS.
- Incorporated by reference new industry standards and update the previous partial incorporation of other standards to require compliance with the complete standards.
- Added new requirements for firefighting systems, shutdown valves and systems, valve closure and leakage, and high pressure/high temperature (HPHT) well equipment.
- Rewrote the subpart in plain language.

In addition to revising subpart H, we are revising the existing regulation (§ 250.107(c)) that requires the use of best available and safest technology (BAST) to follow more closely the Outer Continental Shelf Lands Act's (OCSLA, or the Act) statutory language regarding BAST.

List of Acronyms and References

List of Acronyms and References	
The Act	Outer Continental Shelf Lands Act
AIV	alternate isolation valve
ANSI	American National Standards Institute
API	American Petroleum Institute
APM	Application for Permit to Modify
ASME	American Society of Mechanical Engineers
BAST	Best available and safest technology
BOEM	Bureau of Ocean Energy Management
BOPs	Blowout Preventers
BSDV	Boarding shutdown valves
BSEE	Bureau of Safety and Environmental Enforcement
CSU	column-stabilized-unit
CVA	certified verification agent
DOI	Department of the Interior
DPP	Development and Production Plan
DWOP	Deepwater Operations Plan
E.O.	Executive Order
ESD	emergency shutdown
FPS	floating production systems
FPSO	floating production, storage, and offloading facility
FSV	flow safety valves
GLIV	gas-lift isolation valve
GOM	Gulf of Mexico
H_2S	hydrogen sulfide
HP	high pressure
HPHT	high pressure high temperature
INCs	Incidents of noncompliance
ISO	International Organization for Standardization
IVA	Independent verification agent
LP	low pressure
LSH	level safety high
MAWP	Maximum allowable working pressure
MMS	Minerals Management Service
MOAs	Memoranda of Agreement
MODU	mobile offshore drilling unit
MOU	Memorandum of Understanding
NAE	National Academy of Engineering
NPRM	Notice of Proposed Rulemaking
NTL	Notices to Lessees and Operators
NTTAA	National Technology Transfer and Advancement Act
OESC	Ocean Energy Safety Advisory Committee
OFR	Office of the Federal Register
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
P&ID	piping and instrumentation diagram
PE	Professional Engineer
PLC	programmable logic controller
PRA	Paperwork Reduction Act

PSH	pressure safety high
PSHL	pressure safety high and low
psi	Pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSL	pressure safety low
PSV	pressure safety valve
RFA	Regulatory Flexibility Act
RP	Recommended Practice
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SAFD	safety analysis flow diagram
SDV	shutdown valve
Secretary	Secretary of the Interior
SEMS	Safety and Environmental Management Systems
SIL	safety integrity level
SWRI	Southwest Research Institute
Spec.	Specification
SPPE	Safety and Pollution Prevention Equipment
SSSV	Subsurface safety valve
SSV	surface safety valve
TLPs	tension-leg platforms
TSE	temperature safety element
TSH	temperature safety high
USCG	U.S. Coast Guard
USV	Underwater safety valve
VRU	vapor recovery unit
WI	water injection
WISDV	water injection shutdown valve
WIV	water injection valve

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I. Background

A. BSEE's Statutory and Regulatory Authority

OCSLA, 43 U.S.C. 1331 *et seq.,* was first enacted in 1953, and substantially amended in 1978, when Congress established a National policy of making the OCS ''available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other National needs.'' (43 U.S.C. 1332(3).) In addition, Congress emphasized the need to develop OCS mineral resources in a safe manner ''by well-trained personnel using technology, precautions, and techniques sufficient to prevent or minimize the likelihood of blowouts, loss of well control, fires, spillages, physical obstruction to other users of the waters or subsoil and seabed, or other occurrences which may cause damage to the environment or to property, or endanger life or health.'' (43 U.S.C. 1332(6).) The Secretary of the Interior (Secretary) administers the OCSLA provisions relating to the leasing of the OCS and regulation of mineral exploration and development operations on those leases. The Secretary is authorized to prescribe ''such rules and regulations as may be necessary to carry out [OCSLA's] provisions . . . and may at any time prescribe and amend such rules and regulations as [s]he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the [OCS] . . .'' and that ''shall, as of their effective date, apply to all operations conducted under a lease issued or maintained under the provisions of [OCSLA].'' (43 U.S.C. 1334(a).)

The Secretary delegated most of the responsibilities under OCSLA to BSEE and the Bureau of Ocean Energy Management (BOEM), both of which are charged with administering and regulating aspects of the Nation's OCS oil and gas program. BSEE and BOEM work to promote safety, protect the environment, and conserve offshore resources. BSEE adopts regulations and performs offshore regulatory oversight and enforcement. BSEE's regulatory oversight includes, among other things, evaluating drilling permits, and conducting inspections to ensure compliance with applicable laws, regulations, lease terms, and approved plans and permits.

B. Incorporation by Reference of Industry Standards

BSEE frequently uses standards (*e.g.,* codes, Specifications (Specs.), and Recommended Practices (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 by reference without republishing the standards in their entirety in regulations. The legal effect of incorporation by reference is that the incorporated standards become regulatory requirements. This incorporated material, like any other regulation, has the force and effect of law, and operators, lessees and other regulated parties must comply with the documents incorporated by reference in the regulations. BSEE currently incorporates by reference over 100 consensus standards in its regulations. (*See* § 250.198.)

Federal regulations, at 1 CFR part 51, govern how BSEE and other Federal agencies incorporate documents by reference. Agencies may 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 preamble of the final rule must also discuss the ways that the incorporated materials are reasonably available to interested parties and how those materials can be obtained by interested parties. The Director of the Federal Register will approve each incorporation of a publication by reference in a final rule that meets the criteria of 1 CFR part 51.

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 Web site 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, the American Petroleum Institute (API), provides free online public access to review its key industry standards, including a broad range of technical standards. All API standards that are safety-related and all API standards that are incorporated into Federal regulations are available to the public for free viewing online in the Incorporation by Reference Reading Room on API's Web site. Several of those standards are incorporated by reference in this final rule (as described in parts II.C and IV of this document). In addition to the free online availability of these standards for viewing on API's Web site, hardcopies and printable versions are available for purchase from API. The API Web site address is: *http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents.*[1]

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 office, 45600 Woodland Road, Sterling, Virginia 20166, or by sending a request by email to *regs@bsee.gov.*

C. Production Safety Systems

BSEE's regulations require operators to design, install, use, maintain, and test production safety equipment to ensure safety and the protection of the human, marine, and coastal environments.[2] Operators may not commence production until BSEE approves their production safety system application and BSEE conducts a preproduction inspection. These inspections are necessary to determine whether the operator's proposed production activities meet the OCSLA requirements and BSEE's regulations governing offshore production. The regulatory requirements include, but are not limited to, ensuring that the proposed production operations:

- Conform to OCSLA, as amended, its applicable implementing regulations, lease provisions and stipulations, and other applicable laws;
- Are safe;
- Conform to sound conservation practices and protect the rights of the U.S. in the mineral resources of the OCS;
- Do not unreasonably interfere with other uses of the OCS; and
- Do not cause undue or serious harm or damage to the human, marine, or coastal environments. (*See* §§ 250.101 and 250.106.)

BSEE will approve the operator's production safety system if it meets these criteria.

Typically, well completions associated with offshore production platforms are characterized as either dry tree (surface) or subsea tree completions. The ''tree'' is the assembly of valves, gauges, and chokes mounted on a well casing head and used to control the production and flow of oil or gas. Dry tree completions are typical for OCS shallow water production platforms, with the tree in a ''dry'' state located on the deck of the production platform. The dry tree arrangement allows direct access to valves and gauges to monitor well conditions, such as pressure, temperature, and flow rate, as well as direct vertical well access. Dry tree completions are easily accessible. Because of their easy accessibility, even as oil and gas production moved into deeper water, dry trees were still used on new types of production platforms more suitable for deeper water, such as compliant towers, tension-leg platforms (TLPs), and spars. These platform types gradually extended the depth of usage for dry tree completions to over 4,600 feet of water depth.

Production in the Gulf of Mexico (GOM) now occurs in depths of 9,000 feet of water, however, with many of the wells producing from water depths greater than 4,000 feet utilizing ''wet'' or subsea trees. Subsea tree completions are done with the tree located on the seafloor. These subsea completions are generally tied back to floating production platforms, and from there the production moves to shore through pipelines. Due to the location on the seafloor, subsea trees or subsea completions do not allow for direct access to valves and gauges, but the pressure, temperature, and flow rate from the subsea location is monitored from the production platform and, in some cases, from onshore data centers.

In conjunction with all production operations and completions, including both wet and dry trees, there are associated subsurface safety devices designed to prevent uncontrolled releases of reservoir fluid or gas.

[1] To review these standards online, go to the API publications Web site 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.

[2] The relevant provisions of the existing regulations, and the provisions of this final rule, typically apply to ''you,'' defined by existing § 250.105 as ''a lessee, the owner or holder of operating rights, a designated operator or agent of the lessees(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement.'' For convenience, however, throughout this document we refer to the parties required to comply with the provisions of the existing regulations and this final rule as the ''operator'' or ''operators,'' unless explicitly stated otherwise.

Most of the current regulatory requirements for production safety systems are contained in subpart H of part 250 of BSEE's existing regulations (existing §§ 250.800 through 250.808). Revision of those requirements is the primary focus of this rulemaking.

II. Basis and Purpose of This Rule

A. Developments in Offshore Production

The existing regulations on production safety systems that this final rule is amending were first published on April 1, 1988. (*See* 53 FR 10690). Since that time, various sections have been updated, and BSEE has issued several Notices to Lessees and Operators (NTLs) to clarify the regulations and to provide guidance to lessees and operators.[3]

As discussed in part I.C of this document, subsea trees and other technologies have evolved, and their use has become more prevalent offshore, over the last 28 years, especially as more and more production has shifted from shallow waters to deepwater environments. This includes significant developments in production-related areas as diverse as foam firefighting systems; electronic-based emergency shutdown (ESD) systems; subsea pumping, waterflooding, and gas lift; and new alloys and equipment for high temperature and high pressure wells. The subpart H regulations, however, have not kept pace with those developments.

B. Proposed Revisions to Subpart H

On August 22, 2013, BSEE published a Notice of Proposed Rulemaking (the proposed rule) in the **Federal Register** entitled ''Oil and Gas and Sulphur Operations on the Outer Continental Shelf—Oil and Gas Production Safety Systems.'' (*See* 78 FR 52240.) The purpose of that proposed rule was to improve worker safety and protection of the marine and coastal environment by helping reduce the number of production-related incidents resulting in oil spills, injuries and fatalities. The proposed rule was intended to keep pace with the changing technologies that enable the industry to develop resources in deeper waters (which often involves placing safety equipment on the seabed rather than on a surface platform) by addressing issues such as production safety systems, subsurface safety devices, safety device testing, and production processing systems and areas, and by incorporating best practices currently being deployed by industry leaders.

The comment period for the proposed rule was originally set to close on October 21, 2013. However, in response to several requests, BSEE published a notice on September 27, 2013 (78 FR 59632), extending the comment period until December 5, 2013.

As discussed in part IV.C of this document, BSEE received 57 separate written comments on the proposed rule from a variety of interested stakeholders (*e.g.,* industry, environmental groups, and other non-governmental organizations).

After the close of the comment period, BSEE subject matter experts and decision-makers carefully considered all of the relevant comments in developing this final rule. In part IV of this document, BSEE responds to those comments and discusses how several provisions of the proposed rule were revised in this final rule to address concerns or information raised by commenters.

As a result of BSEE's consideration of all the relevant comments and other relevant information, BSEE has developed this final rule, which is intended to improve worker safety and protection of marine and coastal ecosystems by helping to reduce the number of production-related incidents resulting in oil spills, injuries, and fatalities.

Among other significant changes to the existing regulations, this final rule establishes new requirements for the design, testing, maintenance, and repair of SPPE, using a lifecycle approach. The lifecycle approach involves careful consideration and vigilance throughout SPPE design, manufacture, operational use, maintenance, and decommissioning of the equipment. It is a tool for continual improvement throughout the life of the equipment. The lifecycle approach for SPPE is not a new concept, and its elements are discussed in several industry documents already incorporated by reference in the existing regulations (*see* § 250.198), such as API Spec. 6A, API Spec. 14A, and API RP 14B. This final rule codifies aspects of the lifecycle approach into the regulations and brings more attention to its importance.

BSEE's focus in the development of this rule has been, and will continue to be, improving worker safety and protection of the environment by helping to reduce the number of production-related incidents resulting in oil spills, injuries and fatalities. For example, there have been multiple incidents, including fatalities, injuries, and facility damage related to the mechanical integrity of the fire tube for tube-type heaters. BSEE is aware that this type of equipment has not been regularly maintained by industry. In the final rule, BSEE is requiring that this type of equipment be removed and inspected, and then repaired or replaced as needed, every 5 years. This requirement will improve equipment reliability to help limit incidents associated with the mechanical integrity of the fire tubes.

Three existing NTLs are directly related to issues addressed in this rulemaking:

- NTL No. 2011–N11, *Subsea Pumping for Production Operations;*
- NTL No. 2009–G36, *Using Alternate Compliance in Safety Systems for Subsea Production Operations;* and
- NTL No. 2006–G04, *Fire Prevention and Control Systems.*

Most of the elements from these NTLs are codified in this final rule. After the final rule is effective, BSEE intends to rescind these NTLs and remove them from the *BSEE.gov* Web site. BSEE may issue new NTLs to address any elements of those NTLs that are consistent with but not expressly incorporated in the final rule.

C. Summary of Documents Incorporated by Reference

BSEE is incorporating by reference one new standard in the final rule, API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009. As discussed in the standard, API 570 covers inspection, rating, repair, and alteration procedures for metallic and fiberglass-reinforced plastic piping systems and their associated pressure relieving devices that have been placed in service. The intent of this code is to specify the in-service inspection and condition-monitoring program that is needed to determine the integrity of piping systems. That program should provide reasonably accurate and timely assessments to determine if any changes in the condition of piping could compromise continued safe operation. It is also the intent of this code that owners/users respond to any inspection results that require corrective actions to assure the continued integrity of piping consistent with appropriate risk analysis. Items discussed in this standard include inspection plans, condition monitoring methods, pressure testing of piping systems, and inspection recommendations for repair or replacement.

The other standards referred to in this final rule are already incorporated by

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[3] This includes NTL–2006–G04, *Fire Prevention and Control Systems* (2006), and NTL–2009–G38, *Using Alternate Compliance in Safety Systems for Subsea Production Operations* (2009). All NTLs can be viewed at: *http://www.bsee.gov/Regulations-and-Guidance/Notices-to-Lessees/index/.*

reference in other sections of BSEE's existing regulations. BSEE is incorporating more recently reaffirmed versions of those standards in this rule, as follows:

• BSEE is incorporating a more recently reaffirmed version of American National Standards Institute (ANSI)/API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1996; Reaffirmed April 2008. This standard includes the minimum acceptable standards for verification testing of surface safety valves (SSVs)/underwater safety valves (USVs) for two performance requirement levels.

• BSEE is also incorporating a more recently reaffirmed version of ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Reaffirmed June 2012. This standard provides the minimum acceptable requirements for subsurface safety valves (SSSVs), including all components that establish tolerances and/or clearances that may affect performance or interchangeability of the SSSVs. It includes repair operations and the interface connections to the flow control or other equipment, but does not cover the connections to the well conduit.

• BSEE is incorporating a recently reaffirmed version of API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed January 2013. This standard provides minimum requirements and guidelines for the design and installation of new piping systems on production platforms located offshore. This document covers piping systems with a maximum design pressure of 10,000 pounds per square inch gauge (psig) and a temperature range of −20 degrees to 650 degrees Fahrenheit.

• BSEE is incorporating a more recently reaffirmed version of API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Fifth Edition, July 2008, Reaffirmed April 2013. This RP sets minimum requirements for the design, installation, and maintenance of electrical systems on fixed and floating petroleum facilities located offshore. This RP is not applicable to mobile offshore drilling units (MODUs) without production facilities. This document is intended to bring together in one place a brief description of basic desirable electrical practices for offshore electrical systems. The RP recognizes that special electrical considerations exist for offshore petroleum facilities, including inherent electrical shock, space limitations, corrosive marine environment, and motion and buoyancy concerns.

• BSEE is incorporating a recently reaffirmed version of API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed January 2013. This standard assembles into one document useful procedures for planning, designing, and arranging offshore production facilities, and performing a hazards analysis on open-type offshore production facilities.

• BSEE is incorporating a more recently reaffirmed version of ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Addendum 1, June 2010. This standard states that the adoption of a quality management system should be a strategic decision of any organization. The design and implementation of an organization's quality management system is influenced by its organizational environment, its varying needs, its particular objectives, the product it provides, and its size and organizational structure.

In addition, this rule incorporates API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997, Reaffirmed November 2002. The purpose of this RP is to provide guidelines for classifying locations at petroleum facilities as Class I, Division 1 and Class I, Division 2 for the selection and installation of electrical equipment.

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

After consideration of all relevant comments, BSEE made a number of revisions to the proposed rule language in the final rule. We are highlighting several of these changes here because they are significant, and because multiple comments addressed these topics. A discussion of the relevant comments, including BSEE's specific responses, is found in part IV of this document. All of the revisions to the proposed rule language made after consideration of relevant comments are explained in more detail in that part. The significant revisions made in response to comments include:

1. Best Available and Safest Technology (BAST)—§ 250.107(c)

BSEE proposed to revise the BAST provisions in existing § 250.107 in order to align the regulatory language more closely with the statutory BAST language in OCSLA, to clarify BSEE's expectations, and to make it easier for operators to understand when they must use BAST. BSEE proposed to delete existing paragraph (d) (regarding authority of the Director to impose additional BAST measures) and to revise paragraph (c) to include more of the statutory language and to provide an exception from use of BAST when an operator demonstrates that the incremental benefits of using BAST are insufficient to justify its incremental costs.

BSEE received numerous comments on this proposed change. Among other issues, some commenters stated that the proposed language failed to confirm BSEE's prior position regarding compliance with BSEE's regulations being considered the use of BAST. As explained in more detail in part IV.C of this document, after consideration of the comments and further deliberation, BSEE has revised and reorganized final § 250.107(c) to address many of these issues. The revised language clarifies BSEE's position that compliance with existing regulations is presumed to be use of BAST until (and unless) the Director makes a specific BAST determination that other technology is required. The final rule also provides that the Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. In addition, the revised language provides a clear path for an operator of an existing facility to request a waiver from use of BAST if the operator demonstrates, and the Director determines, that use of BAST would not be practicable. These revisions are consistent with the statutory language and intent of OCSLA, and will further clarify for operators when use of BAST is or is not required and when that requirement may be waived.

2. Firefighting Systems—§ 250.859

BSEE proposed to revise the firewater systems requirements for both open and totally enclosed platforms. Among other things, BSEE proposed requiring that the firefighting systems conform to API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms. This proposed requirement was in addition to existing § 250.803(b)(8), which only requires firefighting systems to conform to section 5.2 in API RP 14G. Many commenters expressed concerns that incorporating the entire RP would create conflicts with the regulations and subsequent inspection policies because API RP 14G does not include a step-by-step method of designing and installing a complete firefighting system. Furthermore, the commenters noted that API RP 14G discusses multiple types of firefighting systems (*e.g.,* fire water, foam, dry chemical, and gaseous extinguishing agent). The commenters suggested various alternatives for compliance with API RP 14G, including requiring compliance only with applicable firewater system sections of API RP 14G.

BSEE understands that there are many different types of firefighting systems discussed in API RP 14G. Accordingly, in this final rule, BSEE has revised proposed § 250.859(a) to require compliance with the firewater system sections of API RP 14G. This change will clarify BSEE's expectations for compliance with this industry standard. This change will also enhance the overall firewater system operability by requiring compliance with provisions in API RP 14G (*e.g.,* inspection, testing, and maintenance) in addition to section 5.2, as required by the former regulations.

BSEE also made other changes to the proposed § 250.859. Specifically, as suggested by several commenters, we clarified the firefighting requirements to minimize confusion regarding U.S. Coast Guard (USCG) jurisdiction and to separate the firewater requirements for fixed facilities and floating facilities. In particular, we revised § 250.859(a) in the final rule to include requirements for firefighting systems on ''fixed facilities,'' and added final paragraph (b) to clarify the requirements for firefighting systems on floating facilities. Final § 250.859(b) also clarifies that the firewater system must protect all areas where production-handling equipment is located, that a fixed water spray system must be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate, and that the firewater system must conform to the USCG requirements for firefighting systems on floating facilities.

3. Operating Pressure Ranges—§§ 250.851, 250.852, 250.858, and 250.865

BSEE received a number of comments on proposed §§ 250.851(b), 250.852(a), 250.858(b), and 250.865(b), regarding the operating pressure ranges for certain types of equipment, including the pressure safety high and low set points. As discussed in the proposed rule, pressure recording devices must be used to establish the new operating pressure ranges for specific equipment (*i.e.,* pressure vessels, flowlines, gas compressor discharge sensors, and surface pump discharge sensors) at any time when the normalized system pressure changes by a certain pressure or percentage. An operating range is used to establish the safety device set points that would trigger a component shut-in. Multiple commenters expressed concerns about the proposed change in operating pressures that would trigger a production safety system shut-in. Commenters also discussed the need to help prevent nuisance shut-ins (*i.e.,* shut-ins that occur under normal operating conditions when a safety device's operating pressures are set too narrowly).

BSEE is requiring the operating pressure ranges because we are aware that not all operators monitor how the pressure regimes are changing. Nonetheless, to help prevent nuisance shut-ins, the final rule allows operators to use a more conservative approach by resetting the operating pressure at an operating range that is lower than the specified change in pressure. To clarify how a new operating pressure range can be established, BSEE added language to the appropriate locations in final §§ 250.851, 250.852, 250.858, and 250.865 stating that once system pressure has stabilized, pressure recording devices must be used to establish new operating pressure ranges. The revised language also clarifies that the pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. Establishing new operating ranges based on these parameters will help prevent nuisance shut-ins, by basing the shut-in set points on an identified, stabilized baseline. BSEE also added a minimum time provision to each of these final provisions to ensure that the system pressure is stable before setting the operating ranges. The time interval limits were set, in part, because pressure spikes and/or surges may not be discernable in a range chart if the run time is too long.

4. Emergency Shutdown System—§ 250.855

In proposed § 250.855, BSEE retained the ESD requirements from § 250.803(b)(4) in the existing regulations, and clarified that the breakable loop in the ESD system is not required to be physically located on the facility's boat landing; however, in all instances, the breakable loop must be accessible from a vessel adjacent to or attached to the facility. A commenter expressed concern that the proposed rule referenced only pneumatic-type valves, while current technology incorporates electronic switching devices.

After considering the issues raised in the comment and reviewing current technology, BSEE has revised proposed § 250.855(a) in the final rule to provide that electric ESD stations should be wired as ''de-energize to trip'' or as supervised circuits. Since BSEE is now allowing electric ESD switches, BSEE wants to ensure that ESD equipment is fully functional, because the key role of the ESD system is to shut-in the facility in an emergency. Therefore, BSEE also added new language clarifying that all ESD components should be of high quality and corrosion resistant, and that ESD stations should be uniquely identified. These revisions are necessary to help ensure that these newer types of ESD stations function properly and to assist personnel in recognizing the ESD location for activation in an emergency.

In addition to the differences between the proposed and final rules discussed here and in part IV, BSEE also made minor changes to the proposed rule language in response to comments suggesting that BSEE eliminate redundancy, clarify potentially confusing language, streamline the regulatory text, or align the language in the rule more closely with accepted industry terminology. BSEE also made other revisions to this final rule to correct grammatical or clerical errors, eliminate ambiguity, and further clarify the intent of the proposed language.

E. Deferred Compliance Dates

The final rule is effective on November 7, 2016. However, BSEE has deferred the compliance dates for certain provisions of the final rule until the times specified in those provisions and as discussed in more detail in part IV of this document.

Compliance with § 250.801(a)(2) for requirements related to boarding shutdown valves (BSDVs) and their actuators as SPPE is deferred until September 7, 2017.

Compliance with § 250.851(a)(2), regarding District Manager approval of existing uncoded pressure and fired vessels that are not code stamped according to ANSI/American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, is deferred until March 1, 2018.

Compliance with the elements of § 250.859(a)(2) requiring all new firewater pump drivers to be equipped with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system is deferred until September 7, 2017.

III. Final Rule Derivation Table

The final rule restructures the provisions of existing subpart H. The new regulations are divided into shorter, easier-to-read sections. These sections are more logically organized, as each section focuses on a single topic instead of multiple topics, as found in each section of the existing regulations. To assist in understanding the revised subpart H regulations, the following table shows how sections of the final rule correspond to the provisions in former subpart H:

Current regulation	Final Rule
§ 250.800 General requirements.	§ 250.800 General.
§ 250.801 Subsurface safety devices.	§ 250.810 Dry tree subsurface safety devices - general.
	§ 250.811 Specifications for SSSVs – dry trees.
	§ 250.812 Surface-controlled SSSVs – dry trees.
	§ 250.813 Subsurface-controlled SSSVs.
	§ 250.814 Design, installation, and operation of SSSVs – dry trees.
	§ 250.815 Subsurface safety devices in shut-in wells – dry trees.
	§ 250.816 Subsurface safety devices in injection wells – dry trees.
	§ 250.817 Temporary removal of subsurface safety devices for routine operations.
	§ 250.818 Additional safety equipment – dry trees.
	§ 250.821 Emergency action and safety system shutdown – dry trees.
	§ 250.825 Subsea tree subsurface safety devices - general.
	§ 250.826 Specifications for SSSVs – subsea trees.
	§ 250.827 Surface-controlled SSSVs – subsea trees.
	§ 250.828 Design, installation, and operation of SSSVs – subsea trees.
	§ 250.829 Subsurface safety devices in shut-in wells – subsea trees.
	§ 250.830 Subsurface safety devices in injection wells – subsea trees.
	§ 250.832 Additional safety equipment – subsea trees.
	§ 250.837 Emergency action and safety system shutdown – subsea trees.
§ 250.802 Design, installation, and operation of surface production-safety systems.	§ 250.819 Specification for surface safety valves (SSVs).
	§ 250.820 Use of SSVs.
	§ 250.833 Specification for underwater safety valves (USVs).
	§ 250.834 Use of USVs.
	§ 250.840 Design, installation, and maintenance - general.
	§ 250.841 Platforms.
	§ 250.842 Approval of safety systems design and installation features.
§ 250.803 Additional production system requirements.	§ 250.850 Production system requirements - general.
	§ 250.851 Pressure vessels (including heat exchangers) and fired vessels.
	§ 250.852 Flowlines/Headers.

Current regulation	Final Rule
	§ 250.853 Safety sensors.
	§ 250.855 Emergency shutdown (ESD) system.
	§ 250.856 Engines.
	§ 250.857 Glycol dehydration units.
	§ 250.858 Gas compressors.
	§ 250.859 Firefighting systems.
	§ 250.862 Fire and gas-detection systems.
	§ 250.863 Electrical equipment.
	§ 250.864 Erosion.
	§ 250.869 General platform operations.
	§ 250.871 Welding and burning practices and procedures.
§ 250.804 Production safety-system testing and records.	§ 250.880 Production safety system testing.
	§ 250.890 Records.
§ 250.805 Safety device training.	§ 250.891 Safety device training.
§ 250.806 Safety and pollution prevention equipment quality assurance requirements.	§ 250.801 Safety and pollution prevention equipment (SPPE) certification.
	§ 250.802 Requirements for SPPE.
§ 250.807 Additional requirements for subsurface safety valves and related equipment installed in high pressure high temperature (HPHT) environments.	§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.
§ 250.808 Hydrogen sulfide.	§ 250.805 Hydrogen sulfide.
NEW SECTIONS	
§ 250.803 What SPPE failure reporting procedures must I follow?	
§ 250.831 Alteration or disconnection of subsea pipeline or umbilical.	
§ 250.835 Specification for all boarding shutdown valves (BSDV) associated with subsea systems.	
§ 250.836 Use of BSDVs	
§ 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?	
§ 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?	
§ 250.854 Floating production units equipped with turrets and turret-mounted systems.	
§ 250.860 Chemical firefighting system.	
§ 250.861 Foam firefighting systems.	
§ 250.865 Surface pumps.	
§ 250.866 Personnel safety equipment.	
§ 250.867 Temporary quarters and temporary equipment.	
§ 250.868 Non-metallic piping.	
§ 250.870 Time delays on pressure safety low (PSL) sensors.	
§ 250.872 Atmospheric vessels.	
§ 250.873 Subsea gas lift requirements.	
§ 250.874 Subsea water injection systems.	
§ 250.875 Subsea pump systems.	
§ 250.876 Fired and exhaust heated components.	

IV. Comments on the Proposed Rule and BSEE's Responses

A. Overview

In response to the proposed rule, BSEE received 57 separate sets of comments from individual entities (companies, industry organizations, or private citizens). (One comment included 1,527 individual letters, as an attachment, although the content of all of these letters was substantially the same.) Some entities submitted comments multiple times. All comments are posted at the *Federal eRulemaking Portal: http://www.regulations.gov*. To access the comments, enter ''BSEE–2012–0005'' in the search box. BSEE reviewed all comments submitted. For the complete list of public comments with summaries of Responses, refer to the comment-response file located in the rulemaking docket.

In addition to the comments on all provisions of the proposed rule, BSEE solicited comments on certain issues related to those proposed provisions, including:

• Organization of the rule based on use of subsea trees and dry trees;
• Lifecycle approach to other types of critical equipment, such as blowout preventers (BOPs);
• Failure Reporting and Information Dissemination; and
• Third-party Certification Organizations.

BSEE also solicited comments and requested information on other topics that were indirectly related to, but outside the specific scope of, this rulemaking. These topics included:

• Opportunities to limit emissions of natural gas from OCS production equipment; and
• Opportunities to limit flaring of natural gas.

BSEE requested comments on natural gas emissions and flaring to inform future policies and potential rulemakings. Since the information provided in response to these topics is not directly related to, and was not considered in developing, this final rule, we have not discussed those comments or information in this document.

B. Summary of General Comment Topics

In addition to comments on specific provisions of the proposed rule, various commenters raised more general issues, including:

• Extension of the public comment period;
• BSEE and USCG jurisdiction; and
• Arctic production safety systems.

The following is a summary of, and BSEE's responses to, comments on these topics. BSEE's responses to more specific comments on proposed provisions are addressed in the ''Section-by-Section'' discussion in part IV.C of this document.

1. Requests for an Extension of the Public Comment Period

BSEE received a number of comments requesting an extension of the public comment period. In response to these requests, BSEE extended the public comment period by 45 days. Some commenters also requested that BSEE hold a public workshop on the proposed rule.

BSEE determined that the extension of the public comment period was sufficient for the public to review, understand, and comment on the proposed rule and thus, that a workshop was not necessary. In addition, BSEE determined that a public workshop would result in significant delays in developing and publishing a final rule, which would also delay the improvements in safety and environmental protection intended by the final rule with no commensurate benefits to justify that delay.

2. BSEE and USCG Jurisdiction

BSEE received comments on a number of provisions in the proposed rule expressing concerns that BSEE was reaching beyond its authority and trying to regulate activities that are under USCG jurisdiction. Both BSEE and the USCG have jurisdiction over different aspects and components of oil and gas production safety systems. These regulations apply only to operations that are under BSEE authority. OCSLA directs that the Secretary prescribe regulations necessary to provide that OCS operations are ''conducted in a safe manner by well-trained personnel using technology, precautions, and techniques sufficient to prevent or minimize the likelihood of blowouts, loss of well control, fires, spillages,. . . or other occurrences which may cause damage to the environment or to property, or endanger life or health.'' (43 U.S.C. 1332(6).) Those regulations apply to all operations conducted under an OCS lease. (43 U.S.C. 1334(a).)

To promote interagency consistency in the regulation of OCS activities, and to describe the agencies' respective and cooperative roles, BSEE and USCG have signed formal memoranda of understanding (MOUs) and memoranda of agreement (MOAs). Those memoranda recognize that, in many respects, BSEE and USCG share responsibility and authority over various aspects of safety and environmental protection related to oil and gas operations on the OCS. The memoranda reflect that BSEE has, and exercises, authority to regulate safety and environmental functions related to OCS facilities, including: developing regulations governing OCS operations, permitting, conducting inspections and investigations, enforcing regulatory requirements, and overseeing oil spill response planning and preparedness. Similarly, the memoranda reflect USCG's authority to regulate the safety of life, property, and navigation and protection of the environment on OCS units and vessels engaged in OCS activities, as well as its authority to regulate workplace safety and health, workplace activities, conditions and equipment on the OCS, and oil spill preparedness and response.

The various memoranda are intended to minimize duplication of effort and promote consistency of regulations and policies where shared responsibilities exist (including, for example, issues related to both fixed and floating facilities) but do not limit either agency's statutory authorities and responsibilities. The USCG–BSEE memoranda are available on BSEE's Web site at: *https://www.bsee.gov/newsroom/partnerships/interagency*.

Numerous comments were submitted regarding BSEE and USCG jurisdiction in connection with multiple sections within the rule. Some comments cited jurisdictional concerns as a general reason why a section should not have been included in the proposed rule. Other commenters expressly noted concern that BSEE's crossing of jurisdictional lines with the USCG could lead to confusion or result in regulatory burdens on the operators. These commenters noted that the USCG has its own rules that govern all or portions of pressurized vessels and fixed and floating facilities. All of the comments that discussed USCG's rules asserted that BSEE lacked some degree of authority concerning the regulation of production safety systems under OCSLA.

Commenters also raised issues concerning BSEE's authority with regard to distinctions between floating and fixed platforms. Commenters described BSEE's authority as limited to fixed platforms and, due to that limitation, they asserted that BSEE does not have the authority to regulate issues regarding floating facilities. These issues were often raised with regard to specific provisions, such as §§ 250.861, Foam firefighting systems, and 250.862, Fire and gas-detection systems.

Some comments raised jurisdictional issues regarding sections of the proposed rule dealing with certain technical or safety matters that the commenters asserted are within USCG's area of expertise (*e.g.,* fire and smoke protection, detection and extinguishing systems, pressure vessels, and electrical systems).

BSEE does not agree with the comments suggesting that the provisions in the proposed rule are outside of BSEE's jurisdiction. This rulemaking applies to production operations that BSEE has historically regulated under longstanding regulations consistent with the authority granted by OCSLA to the Secretary and subsequently delegated to BSEE. This final rule is consistent with the USCG–BSEE MOAs and MOUs. Nothing in the USCG–BSEE MOAs or

MOUs limits BSEE's statutory authority as consistently exercised through BSEE's regulations at part 250.

3. Arctic Production Safety Systems.

A number of comments requested that BSEE add specific production safety requirements for the Arctic OCS environment to the final rule.

BSEE does not agree that new Arctic-specific provisions, which were not included in the proposed rule, should be added to this final rule. Prior to approval by BSEE, all proposed oil and gas production operations on the OCS, including in the Arctic, are required to have production safety equipment that is designed, installed, operated, and tested specifically for the surrounding location and environmental conditions of operation. In particular, the existing BSEE regulations (retained in relevant part by this final rule) require that production safety system equipment and procedures for operations conducted in subfreezing climates take into account floating ice, icing, and other extreme environmental conditions that may occur in the area. (*See* § 250.800.) In addition, all production system descriptions included in Development and Production Plans (DPPs), submitted for development and production activities on a lease or unit in any OCS area other than the Western GOM, go through a formal review and comment period by the public, which provides an opportunity for any interested stakeholder to suggest additional safety measures for production facilities in the Arctic.[4] Moreover, because of the unique Arctic environment, BSEE conducts extensive research on enhanced technologies for oil and gas development on the Arctic OCS (*see www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Categories/Arctic-Research*). These research projects and the knowledge gained from them will inform future decisions, rulemaking, and guidance for Arctic OCS operations.

C. Response to Comments and Section-by-Section Summary

This discussion summarizes: all of the regulatory sections in the final rule; specific comments submitted, if any, on each section in the proposed rule; and BSEE's responses to those comments, including whether BSEE made any revisions to the proposed regulatory text in this final rule in response to the comments. The comments and BSEE's responses are organized as follows: General Comments; Economic Analysis Comments; and Section-by-Section Summary and Responses to Comments.

1. General Comments

BSEE received public comments on the following general issues related to the proposed rule that were not specific to any proposed requirement.

Third-Party Certifications

Comment—Commenters asserted that, by including so many third-party certifications of equipment and processes in the proposed rule, BSEE is implying that other proposed requirements that do not call for certifications are somehow less important.

Response—All of the provisions in this final rule are important. The certifications required by this rule are just one tool that BSEE uses to help ensure that operators meet the level of safety and environmental protection mandated under OCSLA. Other provisions of this rule also help meet that mandate through requirements placed directly on the operators.

Employee Qualifications

Comment—Commenters asserted that the rule does not ensure operator qualification requirements for staff responsible for operating the offshore production facility. They suggested that each company permitted to conduct offshore production facility operations should have a written operator qualification program. They recommended that programs should include, at a minimum, an evaluative procedure (including reevaluation as appropriate), explicit reasons why individuals no longer would be qualified, and record-keeping requirements.

Response—BSEE does not agree that any such requirements should be added to this final rule. Operator personnel qualifications are already addressed in the Safety and Environmental Management System (SEMS) regulations in part 250, subpart S, specifically § 250.1915, What training criteria must be in my SEMS program?

Conflicts With Other Regulations

Comment—A commenter asserted that BSEE needs to ensure that the proposed subpart H changes align with the requirements of existing regulations in subparts J, S, I, and O, as well as with the regulatory requirements of other agencies (*i.e.,* USCG). The commenter suggested that many of the conflicts with other subparts in proposed subpart H could be resolved through regulatory changes in the other subparts. The commenter provided several examples to illustrate the concern—*e.g.,* that the subpart J regulations include the BSDV, although there are requirements for BSDVs in proposed subpart H that either supplement or conflict with the existing requirements in subpart J. The commenter also stated that other parts of the proposed rule referred to issues that operators would expect to be addressed under a different subpart (*e.g.,* proposed § 250.800(c)(3) requirements for stationkeeping would be more appropriate in subpart I).

Response—BSEE does not agree with the suggestion that this final rule conflicts with or contradicts any other provision in BSEE's regulations. There may be overlapping requirements in the various subparts, however, BSEE does not agree that there are conflicts. If there is a need for additional clarity, BSEE will issue guidance in the future. For example, the suggestion that the BSDV requirements in proposed subpart H conflict with BSDV requirements in existing subpart J is incorrect. Subpart H applies to any piping downstream of the BSDV, while subpart J's requirements apply to piping upstream of the BSDV. Similarly, the stationkeeping design requirements for floating production facilities in final § 250.800(c)(3) refer to API RP 2SK and API RP 2SM, which are also incorporated by reference in the design requirements for platforms under § 250.901 of subpart I. While the commenter may consider this duplicative, including the same requirements in subpart H and subpart I ensures that the facilities are designed with the production systems in mind and helps prevent conflicts. While BSEE is not aware of any inconsistencies, BSEE will monitor implementation of this final rule to assess whether any confusion arises from any overlap between subpart H provisions and other BSEE regulations. BSEE will consider whether to address any such issues, if they arise, in possible future rulemakings or guidance.

Finally, as previously discussed, this final rule is aligned with the responsibilities and regulations of the USCG.

Impacts on Existing Equipment

Comment—Commenters asserted that the proposed regulations were not clear with respect to the impact of the requirements on existing equipment (such as non-certified SPPE, BSDVs and single bore production risers) that is fit for purpose and performing satisfactorily within the established operating window and design conditions.

[4] *See* 30 CFR 550.267(b). DPPs are reviewed and approved by BSEE's sister agency, BOEM, which also considers the public comments on submitted DPPs.

Response—BSEE does not agree that the proposed rule was unclear as to any potential impacts on existing equipment. BSEE considered the impact on existing equipment designs when specifying the effective dates for new provisions and determined whether and when it is appropriate for new requirements to apply to existing equipment. For example, most existing SPPE is already certified under the existing regulations; this final rule adds a requirement for certification of BSDVs and their actuators, beginning 1 year after publication of the final rule. Also, under the final rule, operators may continue to use existing SPPE, such as BSDVs. However, if a BSDV fails or does not meet the applicable requirements (*e.g.,* final §§ 250.836 and 250.880(c)(4)), then the operator must replace it with a BSDV that meets all of the requirements, including final §§ 250.801 and 250.802.

Similarly, under final § 250.800(c)(2), operators may continue to use single bore production risers that are already installed on floating production systems, although they cannot install new single bore production risers on floating productions systems after the effective date of this final rule (as explained further in part IV.C). However, for already-installed single bore production risers, additional precautions are necessary for wear protection, wear measurement, fatigue analysis, and pressure testing to perform any well operations with the tree removed. This is consistent with established BSEE policy and approvals for well operations using single bore production risers.

Pew Arctic Standards Report

Comment—A commenter asserted that the Pew Charitable Trusts' September 2013 Arctic Standards Report identified a number of improvements that could be made in BSEE's regulations. The commenter requested that BSEE review and incorporate specific sections of this report related to the subpart H rulemaking.[5]

Response—BSEE reviewed the information provided in the Pew Arctic report, which only addresses Arctic operations. This rulemaking, however, applies to production operations in all OCS regions; the requirements are not specific to one area of the OCS. As previously mentioned, the existing BSEE regulations already require that production safety system equipment and procedures for operations located in subfreezing climates take into account floating ice, icing, and other extreme environmental conditions that may occur in the area. This final rule does not change that requirement. The sections of the report the commenter cited are outside the scope of this rulemaking and address matters not proposed for public notice and comment through the proposed rule.

2. Economic Analysis Comments

BSEE received public comments on the following issues related to the initial economic analysis for the proposed rule and the economic analysis summary in the proposed rule.

Facility Modifications

Comment—A commenter asserted that the initial economic analysis did not reflect the extensive facility modifications that the proposed rule would trigger. The commenter asserted that the agency failed to consider the economic impact of codifying numerous NTLs and industry practices. One commenter specifically questioned the estimated impact on existing fire-fighting systems designed in accordance with the existing regulations and previously approved by BSEE.

Response—BSEE disagrees with the suggestion that we have underestimated the potential cost impacts of this rule. Many of the provisions in the proposed rule were based on existing policy and guidance contained in permit conditions and NTLs. NTLs provide guidance to operators on compliance with existing regulations. BSEE included any costs associated with existing regulatory policy and guidance and industry practices in the baseline of the economic analysis. As specified by Executive Order (E.O.) 12866 and Office of Management and Budget (OMB) Circular A–4, ''Regulatory Analysis'' (2003), which provides guidance to Federal agencies on the preparation of economic analyses, BSEE estimates the costs of a rule resulting from modifications or new provisions in the rule that cause changes from the baseline. Pursuant to OMB Circular A–4, the baseline represents the agency's best assessment of what the world would be like without the new rule. The baseline includes all practices that are already incorporated into industry or regulatory standards, and that would continue to exist even if the new rule were not adopted. For economic analysis purposes, we assume that operators are already following the published NTLs in order to comply with existing regulations; thus, there is no change in industry practices, and no additional costs, when such practices are codified in the regulations.

In particular, the requirements for the firefighting systems in the final rule are consistent with the requirements in the existing BSEE regulations. The costs for the chemical firefighting systems and the inspection and testing of foam in the foam firefighting systems are addressed in the final economic analysis for this rule.

Impacts on Small Businesses

Comment—A commenter asserted that the bureau failed to accurately determine the impacts on small businesses operating offshore and on those businesses supporting the offshore industry through services and equipment.

Response—In the Regulatory Flexibility Act (RFA) determination for this final rule (*see* part V of this document), BSEE estimated that there are 99 companies with active operations on the OCS and approximately 54 companies operating on the OCS that are considered small businesses. However, analyses conducted under the RFA are only required to consider the direct impacts of a new regulation. The indirect impacts of a regulation, or the effects of the regulation on industries that support the directly affected industry, are not considered in an RFA determination or analysis.

As explained in the RFA discussion in part V, BSEE estimated that the total annual cost of the rule per small entity would be about $18,000, which BSEE determined is not a significant economic impact. More details about these estimates are in the RFA discussion in part V of this document.

Impacts on Existing Operations

Comment—A commenter asserted that, while the proposed rule is intended primarily to codify standard industry practice and clarify existing regulations, BSEE had not acknowledged the impact of the proposed rule on existing operations and that the initial economic analysis grossly underestimated the actual cost.

Response—BSEE disagrees with those comments. The initial economic analysis adequately addressed the significant new costs that BSEE anticipated at the time of the proposed rule. However, as explained in more detail in part V of this document, the final economic analysis includes several adjustments to the estimated costs of the final rule, based on comments on the proposed rule and on changes to existing practices that BSEE now expects will occur as a result of the final

[5] Examples of the specific topics in the Pew Arctic report referenced by the commenter included: Tank Performance Standards; Critical Operations Curtailment; and Equipment Design and Operating Performance Standards.

rule. For example, the requirements for the firefighting systems in the final rule are consistent with the requirements in the existing BSEE regulations. The costs for the chemical firefighting systems and the inspection and testing of foam in the foam firefighting systems are addressed in the final economic analysis for this rule.

Uncertainty of Regulatory Benefits

Comment—A commenter asserted that the proposed rule did not discuss why the new requirements are necessary and asked what incidents may be avoided by the proposed requirements. The commenter noted that although the bureau did conduct a break-even analysis for the proposed rule, since the regulatory benefits are highly uncertain, neither the proposed rule notice nor the initial economic analysis discussed the regulatory benefits of the proposed rule.

Response—BSEE does not agree that the proposed rule did not explain why the proposed requirements were necessary. The preamble to the proposed rule adequately described the general and specific purposes of the proposal. (*See* 78 FR 52241) In addition, as discussed in part V of this document, BSEE follows E.O. 12866 and 13563 and OMB Circular A–4 in performing its economic analyses. The costs and benefits related to this final rule are presented in the final economic analysis, available in the public docket and summarized in part V. The final economic analysis includes a break-even analysis, describes the types of incidents that could be avoided, and estimates the cost savings that would result by implementing the final rule. The full economic analysis describes in detail BSEE's data, methodology, and results for the benefits analysis. The potential benefits resulting from the final rule include the potential reduction in oil spills and injuries to workers, which are difficult to quantify and are highly dependent on the actual reduction in the probabilities of the incidents occurring. Due to this uncertainty, BSEE conducted a break-even analysis consistent with the guidance provided in OMB Circular A–4.

Reports of Design Changes or Modifications

Comment—One commenter questioned the initial economic analysis conclusion that there would only be a limited number of reports of design changes or modifications. The estimated labor for BSEE to work with this information is $68. Given this effort by BSEE to analyze the information, the commenter questioned how this new requirement will be of any value to BSEE.

Response—In BSEE's experience, design changes do not happen frequently; therefore, we do not anticipate very many reports based on this requirement (*i.e.,* BSEE estimated 1 change per year). Since the reporting of design changes to BSEE is a new requirement, the number of design change reports is only an estimate; BSEE will adjust the frequency of design changes based on the actual number when we renew the relevant information collection in 3 years. The reporting of design changes due to the failure of critical safety equipment, as well as the reporting of such failures, is extremely important to the development of a knowledge-base that can be used to analyze past equipment failures and responses and help to prevent future failures that would jeopardize safety and environmental protection on the OCS.

Estimated Costs for Marine Construction

Comment—A commenter questioned the accuracy of the estimated costs for marine construction in the initial economic analysis because the estimates did not include any costs (or the time) for transportation on the OCS.

Response—Although the commenter did not explain what it meant by ''marine construction,'' BSEE assumes it was referring to the cost of transportation on the OCS. BSEE does not agree that the total costs of transportation on the OCS should be included in the costs of the rule because operators can use regularly scheduled trips, coordinating with crew boats or helicopter trips, to achieve compliance with the final rule. There does not need to be a special, separate trip for this purpose. Moreover, trips to and from these facilities already occur frequently and are, therefore, part of the baseline. The costs for the petroleum technician, labor, shipping and materials are discussed in the final economic analysis.

Oil Spill Estimates

Comment—A commenter asserted that BSEE overestimated the amount of spilled oil in the initial economic analysis, and that the estimate of 57 leakage occurrences appears too high. The commenter requested that a list of the incidents considered by BSEE be included in the response to comments in the final rulemaking.

Response—It appears that the commenter assumed that the oil spill volumes estimated in the initial analysis were related to the leakage occurrences. However, the oil spill estimate is not related to leakage incidents or leakage rates. Oil spill volumes refer to oil released into the environment. By contrast, the leakage occurrences refer to leaking SSSVs, which are part of a closed safety system, designed to minimize oil spills by stopping the flow within the tubing if the riser is damaged; thus, that oil is not released into the environment. Based on BSEE data for June 2003 through May 2013, BSEE issued a total of 57 Incidents of Noncompliance (INCs) associated with leakage rates (P–280) under the category of ''Subsurface Safety Device Testing.''

Impacts of BAST

Comment—Several commenters questioned the economic feasibility and impact of using BAST. They also asserted that the initial economic analysis failed to include any costs associated with the proposed revisions to § 250.107(c) and that those potential costs should have been estimated and analyzed in the economic analysis.

Response—This rule does not identify any technology as BAST and merely clarifies the regulatory language to be more in alignment with the statutory language. BSEE disagrees with the suggestions that the revisions to § 250.107(c) constitute either a BAST program or a BAST determination, and that those revisions will impose new costs on operators. As explained in more detail later in this document, the revisions to § 250.107(c) are intended to align the language of that paragraph more closely with the statutory language and intent of the BAST provision in OCSLA (43 U.S.C. 1347(b)). In fact, final § 250.107(c)(1) uses essentially the same language as the statutory provision, although the language in the final regulation is arranged so as to be more clear and easier to follow. Similarly, final § 250.107(c)(2) clarifies and confirms the longstanding principle, stated in former § 250.107(c), that conformance with BSEE regulations qualifies as the use of BAST, unless or until the BSEE Director makes a specific BAST determination that other technologies are required. Thus, since final paragraph (c)(1) merely incorporates and clarifies the statutory language, and paragraph (c)(2) clarifies and reconfirms the existing regulatory language and policy, those provisions do not impose any new BAST requirements or create a new BAST program.[6] Moreover, even assuming that

[6] In fact, several industry comments acknowledged that BSEE has been implementing a BAST program for some time, as discussed later in part IV.C with regard to comments on proposed § 250.107(c).

there were any costs associated with final § 250.107(c)(1) and (2), they would be considered part of the economic baseline, as they merely reflect existing law and practice.

The only arguably significant addition to existing § 250.107(c) is final paragraph (c)(3), which states that the Director may waive the requirement to use BAST for a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable, and that the Director may waive the use of BAST at an existing operation if the operator demonstrates, and the Director determines, that the use of BAST would not be practicable for that operation. However, paragraph (c) in the existing regulation already effectively provided for such an exception from the required use of BAST,[7] although it did not provide any explicit direction as to how to invoke that exception. Final paragraph (c)(3) provides a well-defined path for operators to seek and be granted a waiver from BAST requirements. Moreover, both the exception language in former paragraph (c) and the waiver language in final paragraph (c)(3) are consistent with the statutory BAST language, which states that BAST must be used on existing operations ''whenever practicable.'' Final paragraph (c)(3) embodies the converse of that requirement, and clarifies that use of BAST will not be required on existing facilities when the operator demonstrates, and the Director determines, that it is not practicable. Thus, final paragraph (c)(3) does not impose any new requirements, and any potential costs associated with that provision are properly included in the economic baseline, because final paragraph (c)(3) is consistent with the exception in existing § 250.107(c) and with OCSLA. Nonetheless, BSEE has estimated the minimal potential costs associated with BAST waiver requests and included that estimate in the final economic analysis and the Paperwork Reduction Act burden estimate, as described in part V of this document.[8]

BAST Process

Comment—Another commenter asserted that there was no transparent process for identifying what technology qualifies as ''BAST'' and that, due to the lack of clarity and transparency on what would be required, the cost impact was grossly understated.

Response—BSEE disagrees with this comment. As stated in response to the prior comment, neither proposed nor final § 250.107(c) involves or affects BSEE's process for determining what specific technology is BAST. Revised § 250.107(c) only clarifies, on a non-technology-specific basis, when use of BAST is or is not required, and confirms that conformance with existing BSEE regulations is considered use of BAST unless and until the BSEE Director makes specific determinations that other technologies are BAST. Thus, as previously discussed, there are no costs associated with this section. Further, as several industry comments acknowledged, BAST is already an established part of BSEE regulations. Thus, since final § 250.107(c) is consistent with the statutory requirements of OCSLA and with existing § 250.107(c), any costs that might be attributable to the provision are part of the economic baseline. To the extent the commenter objects to, or wants to suggest improvements to, the process by which BSEE makes BAST determinations, the commenter may submit its views to BSEE. However, those views are beyond the scope of this rulemaking.

Costs for § 250.800—General

Comment—A commenter pointed out that the initial economic analysis did not include cost estimates for proposed § 250.800—General.

Response—BSEE disagrees with the suggestion that revised § 250.800 would impose new costs that should have been included in the economic analysis. That section of the final rule contains essentially the same requirements as existing § 250.800, except for new language added to proposed and final paragraph (c)(2) and new paragraph (d). The new language in paragraph (c)(2) prohibits the installation of new single bore production risers. However, there are no new costs resulting from this new language because BSEE has not approved installation of any new single bore production riser for the last 8 years; BSEE has only approved installation of dual bore risers over that time, and this now represents standard and longstanding industry practice. Therefore, the prohibition of new single bore risers is not a new development, and even assuming there are any costs associated with that prohibition, they are properly included in the baseline because the prohibition reflects existing industry and BSEE practice.

Similarly, new paragraph (d), which was added to the final rule based on comments received, also does not impose any new costs on operators. That paragraph provides general guidance for compliance with subpart H; specifically, that in case of any conflicts between any incorporated standard and any provision in subpart H, the specific regulatory provision controls.

The only other revisions to existing § 250.800 incorporate or clarify the applicability of industry standards, previously incorporated in other sections of BSEE's regulations, to production safety equipment (*e.g.,* productions safety systems on fixed leg platforms). As previously discussed, any costs attributable to incorporation of industry standards are properly included in the baseline because those standards represent generally accepted practices used by the industry in day-to-day operations, particularly those already codified in BSEE's regulations.

SPPE Certification

Comment—A commenter raised the concern that the initial economic analysis related to proposed § 250.801 (SPPE certification) did not discuss costs associated with BSDV certification. The commenter also asserted that the certification requirement was a BAST determination that did not comply with the BAST statute because BSEE did not demonstrate that certified valves perform better than non-certified valves.

Response—We disagree with the comment suggesting that the proposed requirement for certification of SPPE constitutes a BAST determination by the bureau and that such determination is deficient. There is no connection between the SPPE certification process and BAST determinations because, among other reasons, the certification process is not a technology; rather, certification is a verification process. In addition, BSEE has considered the costs of certification of BSDVs and other SPPE in the final economic analysis, as discussed in part V of this document.

Cost for Retaining Documentation

Comment—A commenter stated that costs associated with proposed § 250.802(e) (regarding retention of certain documentation on SPPE for 1 year after decommissioning) were not discussed or analyzed in the initial economic analysis. The commenter did not, however, provide an estimate of the potential costs involved with this proposed requirement.

Response—BSEE agrees with the comment, and the SPPE document retention requirement under final § 250.802(e) is now addressed in the

[7] Existing § 250.107(c) provides that ''You must use the best available and safest technology (BAST) *whenever practical* on all exploration, development, and production operations.'' (Emphasis added.)

[8] The final economic analysis estimates that the total annual cost to all of the affected industry from the waiver provision would be $910.

final economic analysis as well as in the Paperwork Reduction Act (PRA) burden estimates that are discussed in part V of this document.

SPPE Costs

Comment—A commenter asserted that potential costs under proposed § 250.806 were not included in the initial economic analysis.

Response—BSEE assumes that this comment refers to the existing § 250.806, which was reorganized and re-codified in §§ 250.801 and 250.802 of the final rule. Section 250.806 is now reserved. The provisions from § 250.806 of the existing regulations, now in final §§ 250.801 and 250.802, require certification that certain SPPE valves were manufactured under a quality assurance program standard recognized by BSEE, such as API Spec. Q1. Since those provisions were codified in the existing regulations, and rely on existing industry standards, any costs associated with those existing requirements that are retained in final §§ 250.801 and 250.802 are included in the economic baseline. The additional potential costs of complying with the new provisions of the certification requirement are included in the final economic analysis, as discussed in part V.

Costs for Floating Production Unit Safety Systems

Comment—In connection with proposed § 250.854 (Floating production units equipped with turrets and turret-mounted systems), a commenter asserted that costs associated with new requirements were not discussed or analyzed in the economic analysis.

Response—Section 250.854 addresses floating production units with either auto slew systems or swivel stacks. Floating production, storage, and offloading facilities (FPSOs) in the GOM are already in compliance with this section, so it will not result in new costs for existing FPSOs. There are no new costs for floating production units with an auto slew system because final § 250.854 does not require the installation of new equipment. If an operator uses an auto slew system, this provision simply states that the auto slew system must be integrated with the process safety system, which does not require any new activity or equipment.

Similarly, the requirement that a floating production unit with a swivel stack must have a hydrocarbon leak detection system tied in to the process safety system imposes no new costs. These facilities already have a leak detection system, as required in their approved Deepwater Operations Plans (DWOPs), since the FPSO's swivel stack is a critical leak path subject to longstanding DWOP leak detection conditions. Further, there are no additional costs resulting from the requirement to tie the leak detection systems into the process safety system because these requirements are longstanding conditions of approval under the DWOP process for floating production units.

Cost for Glycol Dehydration Units

Comment—A commenter referenced proposed § 250.857(b) and (c) (regarding installation of certain valves on glycol dehydration units), stating that there was no clarity on whether existing glycol dehydration units must comply with this requirement, and noted that if they do need to comply, those costs must be considered. The commenter requested that the final rule address the status of existing equipment.

Response—This requirement is based on API RP 14C, which is already incorporated into BSEE regulations. The final rule simply clarifies that the location of the valves needs to be as close to the glycol contact tower as possible. As previously explained, BSEE includes the costs for following industry standards and existing regulation as part of the economic baseline.

Firefighting Systems

Comment—A commenter noted that proposed new § 250.859 would require that certain firefighting systems comply with all of API RP 14G, while the corresponding provision in existing § 250.803(b)(8) only required firefighting systems to comply with section 5.2 of API RP 14G. The commenter asserted that the proposed change would have significant implications, and that the costs associated with the incorporation of the entire document were not considered in the initial economic analysis.

Response—BSEE does not agree that any costs associated with firefighting systems meeting any provisions of API RP 14G must be added to the costs of the rule. As previously stated, and as explained in the final economic analysis, any costs associated with following existing industry standards are part of the economic baseline. In addition, as previously explained, BSEE has revised final § 250.859(a) to require that firewater systems need to comply only with the relevant provisions of API RP 14G, which eliminates potential confusion as to whether firewater systems would have to meet new requirements under API RP 14G that currently do not apply to such systems.

Chemical Firefighting Systems

Comment—A commenter asserted that proposed § 250.860 (regarding chemical firefighting systems) included new requirements from an existing NTL, and that BSEE should have analyzed the costs of those requirements.

Response—BSEE disagrees. As already stated, any costs associated with following the guidance provided in existing NTLs, and now contained in this final rule, are part of the economic baseline. Consistent with OMB Circular A–4, the baseline includes all practices that are already incorporated into industry and regulatory standards, and that would continue even if the new regulations were never imposed. Since NTLs interpret, and provide guidance on how to comply with, existing regulations, BSEE expects that industry already follows the NTLs to comply with the relevant existing regulations and to ensure safety and reliability of operations.

Pressure Recording Devices

Comment—A commenter noted that proposed § 250.865(b) contained new requirements regarding pressure recording devices, and that there was no discussion in the proposed rule's preamble or the initial economic analysis concerning the need for and the costs of these new requirements.

Response—BSEE does not agree that there are new costs associated with this provision that need to be accounted for as costs in the economic analysis because the pressure recording requirements in paragraph (b) were already required by § 250.803(b)(1)(iii) of the existing regulations and, thus, are part of the economic baseline.

Atmospheric Vessels

Comment—A commenter asserted that proposed § 250.872(a), regarding atmospheric vessels, contained new requirements and that there was no discussion in the proposed rule or the initial economic analysis concerning the need for or costs of these new requirements.

Response—BSEE disagrees. Proposed—and now final—§ 250.872(a) requires compliance with API RP 500 and API RP 505, both of which are incorporated in existing BSEE regulations (*e.g.,* §§ 250.114, 250.802 250.803). Therefore, there are no new costs, beyond those included in the baseline, associated with this section.

Inspection Costs for Fire and Exhaust Heated Components

Comment—A commenter asserted that the estimated costs ($5,000) in the initial economic analysis for proposed

§ 250.876, regarding inspection of fired and exhaust heated components, were too low. The commenter suggested that a better cost estimate would be at least 3 or 4 times that amount, and that the ability to obtain a qualified third-party to inspect these components in the timeframe required may be difficult.

Response—BSEE agrees that these costs may be higher than what was originally estimated and has adjusted the costs appropriately in the final economic analysis.

3. Section-by-Section Summary and Responses to Comments

Definitions (§ 250.105)

Section Summary—This section provides definitions of terms used throughout part 250.

Regulatory text changes from the proposed rule—BSEE did not propose any changes to this section of the existing regulations in the proposed rule and has made no changes in the final rule.

Comment—One commenter suggested that BSEE add a definition for the term ''platform'' to the final rule.

Response—BSEE did not propose to define that term, and has decided not to add the commenter's suggested definition to the final rule. The word ''platform'' can have several meanings within BSEE's regulations, depending on where and how it is used. In addition, the suggested definition was specifically related to the commenter's concerns about future development of the Arctic OCS. BSEE recognizes the importance of the concerns related to future Arctic development and recently focused on Arctic-related issues in a separate final rulemaking, as already discussed in part IV.B.3.

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

Section summary –This section of the existing regulations lays out performance-based and other requirements that operators must meet to protect safety, health, property and the environment. Paragraph (c) of the existing regulation required the use of BAST whenever practical on all exploration, development and production operations, while paragraph (d) authorized the Director to require additional measures to ensure use of BAST.

Regulatory text changes from the proposed rule—BSEE proposed revisions to paragraph (c), and proposed to remove paragraph (d), in order to more closely track the BAST language in OCSLA and to provide additional clarity regarding how the BAST requirements would be implemented. Many of the comments on the proposed changes to this section supported the proposed language, although many industry commenters, while acknowledging issues or concerns related to the existing language, raised concerns related to the potential impact of the proposed language on existing facilities. In the final rule, BSEE has removed existing paragraph (d), as proposed.

However, based on the comments received, BSEE has reorganized and revised the proposed changes to paragraph (c). BSEE has revised final paragraph (c)(1) to track even more closely the language of the relevant OCSLA provision. Final paragraph (c)(2) revises the proposed language to further clarify and confirm that compliance with BSEE regulations will be presumed to constitute the use of BAST, unless and until BSEE's Director determines that other technologies are required in accordance with final paragraph (c)(1). In addition, final paragraph (c)(3) revises the proposed BAST exception language to clarify that the Director may waive the requirement to use BAST for a category of existing operations if the Director determines that use of BAST for that category of operations would be impracticable. That paragraph also clarifies that the Director may waive the requirement to use BAST for an existing operation, if the operator demonstrates, and the Director determines, that using BAST in that operation would be impracticable.

Comments and responses—BSEE received public comments on the following issues related to the proposed revisions to § 250.107 and responds as follows:

Whether Proposed BAST Revision Not Needed/Premature

Comment—Many comments asserted that the proposed changes to § 250.107 are premature and should be delayed until BSEE develops a detailed process for making and implementing BAST determinations and the National Academy of Engineering (NAE) completes a report on BAST.

Response—BSEE disagrees with these comments. BSEE did not propose any changes to or request comments on the internal processes that BSEE uses to evaluate technologies in making BAST determinations. The primary objective of the proposed changes was to better align the regulatory provisions with the statutory mandate.

That statutory provision requires:

On all new drilling and production operations and, wherever practicable, on existing operations, the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies. (43 U.S.C. 1347(b).)

In OCSLA, Congress directed the Secretary to require the use of BAST in these circumstances. Over a period of years, the regulatory language used to implement this statutory provision was modified as the offshore regulations were revised. As noted in the preamble of the proposed rule, BSEE believes that the existing regulatory language does not give full effect to the BAST obligations contained in the Act. (*See* 78 FR 52243.)

Revision of the BAST language in existing § 250.107 is also consistent with the recommendations of the Ocean Energy Safety Advisory Committee (OESC), which was formed following the *Deepwater Horizon* incident to provide advice to the Secretary on issues related to offshore safety. The OESC, which consisted of representatives from industry, Federal government agencies, non-governmental organizations and the academic community, specifically recommended that BSEE revise the BAST regulations to more accurately reflect the statutory language and to ensure the effective implementation of a BAST program.

Thus, BSEE does not believe that the proposed regulatory changes need to be delayed until the internal BAST implementation process is fully developed. In any case, since publication of the proposed rule in 2013, BSEE has developed an internal process defining how technology will be evaluated by BSEE using a transparent and data-driven approach. This internal process was developed with significant input from many industry organizations and was discussed in detail at the BAST Conference hosted by the Ocean Energy Safety Institute on November 12, 2015. Moreover, the NAE final report on BAST, published in January 2014, was considered by BSEE in the development of this internal process. More information about the BAST Conference, NAE final report, and the BAST determination process is currently available on BSEE's BAST Web page at *http://www.bsee.gov/bast/*. Pre-publication copies of the NAE final report are available through BSEE's BAST Web page which links to NAE's Web site, or by going directly to NAE's Web site at:*http://*

www8.nationalacademies.org/onpinews/newsitem.aspx?RecordID=18545.

Whether Proposed Changes to BAST Language Are Unnecessary

Comment—Some commenters asserted that regulatory changes are unnecessary since BSEE already implements an effective BAST program through the combination of regulations, industry standards, plan and permit approvals, alternative compliance approvals, departure approvals, platform verification, inspection and enforcement, data collection, training, and the safety alert program.

Response—While BSEE agrees that it already maintains an effective BAST program, it nevertheless believes that changes to the existing regulatory language are necessary. As described in the proposed rule, and in prior responses to other comments, the changes to existing § 250.107(c) provide greater clarity and ensure consistency between the regulation and the language contained in OCSLA. BSEE agrees that, in many cases, existing regulations (including standards that are incorporated by reference in the regulations) will represent BAST. This is consistent with the intent of the language in existing § 250.107(c).[9] In the final regulations, § 250.107(c)(2) confirms and clarifies that compliance with the regulations is presumed to constitute BAST unless and until the Director makes a determination that other equipment or technology is required as BAST.

Whether Revised BAST Provisions Would Be Disruptive

Comment—Several commenters stated that the proposed rule changes would disrupt an already established BAST process, that they would create uncertainty in the established BAST process, and that the impact of this uncertainty should be considered. Other commenters asserted that industry standards represent BAST.

Response—BSEE does not agree that the proposed or final revisions to § 250.107 would create more uncertainty. The proposed rule language essentially mirrored statutory language that has been in place since 1978 and eliminated ambiguous language that was perceived as potentially inconsistent with the statute. This final rule presents that language in an even clearer way and provides additional clarification on how BAST will be applied, while maintaining and improving alignment with the statutory language. For example, existing § 250.107 did not provide any express parameters for identifying when compliance with the regulations would no longer be considered the use of BAST. The final rule clarifies that this situation would occur when the Director makes a formal BAST determination that specific technology is required.

In addition, BSEE does not agree that consensus-based industry standards that have not been incorporated in applicable BSEE regulations automatically represent BAST. BSEE has incorporated by reference many industry standards into its regulations, and they play an important role in establishing a minimum baseline for the safety of offshore activities and equipment. And compliance with a regulation that incorporates a standard will be presumed to be the use of BAST, unless and until the Director makes a determination to require other technology(ies). However, a determination as to whether a specific, non-incorporated standard reflects BAST would need to be made by the Director on a case-by-case basis.

Whether BAST Determination Process Is Unclear

Comment—Several commenters asserted that the proposed rulemaking was unclear regarding what factors and thresholds BSEE will use when deciding whether it will require an operator to use a certain technology as BAST and how long the operator has to come into compliance. Other commenters asserted that existing facilities should be ''grandfathered'' out of any new BAST requirements.

Response—BSEE has revised § 250.107(c) of the final rule to clarify that the BSEE Director will determine when to apply a particular technology as BAST. This change is consistent with the OCSLA BAST language (and a prior delegation of the Secretary's authority to the Director). Specifically, the Director will:

- Determine when the failure of equipment would have a significant effect on safety, health, or the environment;
- Determine the economic feasibility of the technology;
- Decide whether the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies;
- Decide whether to waive the use of BAST for a category of existing operations because the use of BAST would not be practicable for those operations; and
- Decide whether to waive the use of BAST for an existing operation if the operator of an existing facility requests a waiver and demonstrates, and the Director determines, that the use of BAST in that existing operation would not be practicable.

BSEE does not agree, however, that an automatic ''grandfathering'' provision for existing facilities is appropriate. The language in OCSLA specifically makes BAST applicable to existing operations, provided that it is practicable and that the other determinations specified by the statute are made. BSEE has, however, clarified in final § 250.107(c)(3) the process for requesting a waiver from the use of BAST on existing facilities based on a demonstration by the operator, and a determination by the Director, of impracticability.

Economic Feasibility, Practicability, and Other Considerations in BAST Determinations

Comment—Several comments addressed the criteria and process for making BAST determinations with respect to economic feasibility, practicability, and cost-benefit analyses regarding BAST. It was suggested that BSEE define and publish its determinations for the terms ''economically feasible'' and ''practicable,'' and designate a pre-determined length of time for existing operations to come into compliance.

Commenters also suggested that BAST waivers or exceptions should be accompanied by a description of how the incremental benefits of using BAST were less than the incremental costs and should be subject to public review and comment. Commenters asserted that BSEE should incorporate the factors and thresholds on which it will determine which technology is BAST prior to finalizing the proposed rule, and that BSEE should be the ultimate decisionmaker as to BAST requirements.

Additionally, one commenter stated that the proposed text increases uncertainty in that it appears to require operators to demonstrate that the incremental benefits of using BAST are insufficient to justify the costs in order to obtain an exception, which improperly shifts the burden to the operator.

Response—BSEE agrees that some clarifications and revisions of the benefit-cost determination and the proposed exception language are appropriate. Consistent with Congress' intent concerning the evaluation of costs and benefits, final paragraph (c)(1) now clarifies that the Director will determine

[9] Existing § 250.107(c) states that ''In general, we consider your compliance with BSEE regulations to be the use of BAST.''

whether the incremental benefits of certain technology are clearly insufficient to justify the incremental costs of utilizing BAST.[10] Accordingly, BSEE has removed the cost-benefit language in the exception provision of proposed paragraph (c)(2) from the final rule.[11] In addition, final paragraph (c)(3) clarifies that the Director may waive a BAST requirement for an existing operation if the waiver request demonstrates, and the Director determines, that the use of the BAST in question is not practicable. This is also consistent with Congress' intent that an operator show that use of BAST is not practicable for an existing operation: ''It is, of course, the responsibility of an operator on an existing operation to demonstrate why application of a new technology would not be 'practicable'.'' H.R. Rep. No. 95–1474, at 109 (Aug. 10, 1978).

BSEE does not agree, however, with the comments suggesting that the final rule include definitions or specific factors or ''thresholds'' for economic feasibility and practicability on which the Director will make BAST determinations or waiver decisions, respectively. OCSLA requires that BSEE (through a delegation from the Secretary) make BAST determinations, and BSEE has developed its formal process for BAST determinations in line with that authority. Every BAST determination requires a benefit-cost analysis of its own, to demonstrate that the BAST candidate technology is economically feasible and that it will result in benefits that are not clearly insufficient to justify the costs. For any future BAST determinations, BSEE will specify what is economically feasible for BAST purposes through rulemaking, except in cases involving emergency safety issues. These decisions will be largely technology- and fact-specific, and it would be premature to specify in this rule how such facts will be considered in particular cases.

In any case, the proposed and final revisions of the language in § 250.107(c) do not constitute a BAST determination and do not address BSEE's internal processes for making specific BAST determinations. BSEE revised this section in the final rule in large part to clarify that the BSEE Director will determine when to make those specific BAST determinations in accordance with the statutory criteria.

Similarly, ''practicability'' demonstrations and decisions for waiver requests will depend on the circumstances of the existing operations at issue. However, BSEE expects that unique factors, such as the types or ages of specific facilities or environmental conditions, that make installation of BAST impracticable will be relevant in this decisionmaking.

Time Requirements for BAST Determination Process

Comment—One comment requested that BSEE place a time limit on itself to review requests under the proposed provision allowing an operator to request an exception from using BAST by demonstrating that the incremental benefits are clearly insufficient to justify the incremental costs. The commenter said that BSEE's estimate that it would take an operator 5 hours to prepare the information to satisfy the proposed requirements for an exception is inadequate. The commenter asserted that it would take many more hours to compile, analyze and prepare information that demonstrates to BSEE that the operator's technology fits the exception to BAST. The commenter also asserted that BSEE will require far more time than predicted to analyze and review the information required by the proposed exception provision. Furthermore, the commenter stated that BSEE has not provided any guidance or process for implementing this proposed requirement.

Response—BSEE does not agree with the suggestion that it needs to establish a more-detailed BAST exception (waiver) process or provide guidance for waivers prior to revising § 250.107(c). BSEE may, however, provide guidance on the implementation of the BAST requirements, including the waiver process, in the future.

The commenter's concern that a request for an exception under the proposed language would likely take many hours to complete and review has been effectively resolved by the revisions in final § 250.107(c)(3), which now provides that the operator only needs to demonstrate that use of BAST is not practicable (*i.e.,* the operator does not need to demonstrate that the incremental costs exceed the incremental benefits). BSEE's current estimates as to the time needed for operators and BSEE to take the actions contemplated under the final waiver language are contained in the final economic analysis and the PRA portion of part V of this document.

Definition of ''Failure''

Comment—One commenter requested clarification as to the definition of ''failure'' in the context of the proposed § 250.107(c)(1), which stated that ''[w]herever failure of equipment may have a significant effect on safety, health, or the environment . . . .'' the use of BAST is required. The commenter stated that ''failure'' could have multiple meanings including mechanical failure, electrical failure, or test failure.

Response—BSEE does not agree that a specific definition of ''failure'' is necessary. The relevant language is drawn directly from OCSLA, which states that BAST must be used ''[w]herever failure of equipment would have a significant effect on safety, health, or the environment . . .'' BSEE used this language in the proposed and final rule to provide parameters for the types of failure that trigger the OCSLA requirement to use BAST. The Director would not require the use of BAST equipment if failures of that equipment would not result in a significant effect on safety, health, or the environment. What constitutes failure of equipment depends upon the context of the operation and equipment. Under this section, BSEE is addressing equipment failure as a general matter. Specific provisions related to equipment functionality are addressed in existing regulatory provisions and throughout this final rule.

BAST Discretion and Waiver

Comment—One commenter requested clarification on proposed § 250.107(c)(1)(ii), which proposed that operators must use economically feasible BAST, ''wherever practicable on existing operations.'' The commenter requested clarification as to whether, at the discretion of BSEE personnel, existing equipment that is properly operating under normal conditions would need to be replaced even if it did not pose a threat of a malfunction or failure.

Response—In the final rule, BSEE revised the language of proposed § 250.107(c) to clarify that the Director will make the BAST determinations regarding economic feasibility and other

[10] *See, e.g.,* Report by the Ad Hoc Select Committee on the [OCS], Rep. No. 95–590 at 159 (Aug. 29, 1977) (''A balancing of danger and costs is required. The focus of this [BAST] provision is to require that operations in the [OCS] on leases are to be the safest possible. The regulator is to balance the significance of the procedure or piece of equipment on safety. If adoption of new techniques or equipment would significantly increase safety, and would not be an undue economic hardship on the lessee or permittee, he is to require it. In determining whether an undue economic hardship is involved, the regulator is to weigh incremental benefits, against incremental costs.'') *See also* H.R. Rep. No. 95–1474, at 109 (Aug. 10, 1978) (''[C]onsiderations of costs and benefits should also be done by the regulating agency . . . .'')

[11] Since the final waiver provision does not require the operator to make an incremental cost-benefit demonstration, the comment suggesting that BSEE make the cost-benefit factors for a waiver or exception available for public review is moot.

factors listed in final paragraph (c)(1). BSEE has also clarified the language in final paragraph (c) on the application of BAST to existing operations, consistent with the OCSLA BAST language. Under final § 250.107(c)(3), the Director may waive the requirement to use BAST for a category of existing operations if the Director determines that use of BAST would be impracticable for that category.

In addition, the Director may waive the requirement to use BAST for an existing operation if the operator of an existing facility submits a waiver request demonstrating, and the Director then determines, ''that the use of BAST would not be practicable'' in that operation. For example, if an operator demonstrates, and the Director determines, that such technology(ies) would be unduly difficult or impossible to retrofit at an existing facility, the Director could grant the operator a waiver. In the absence of a waiver, however, existing operations must comply with BAST. As explained in response to other comments, OCSLA expressly requires the use of BAST for existing operations, whenever practicable, so Congress did not view existing technologies inherently to represent BAST.

Regulatory Flexibility Act Compliance Regarding BAST

Comment—Several commenters asserted that BSEE had not met its obligations under the RFA with regard to the proposed BAST language; *i.e.,* that it had not conducted a regulatory flexibility analysis to assess the impact of the proposed provision on small entities. Commenters also noted that, in the proposed rule, BSEE concluded that this rule is not likely to have a significant economic impact and, therefore, an initial RFA analysis was not required by the RFA, even though BSEE provided a contractor-prepared initial regulatory flexibility analysis in support of the certification. The commenters asserted, however, that this analysis was inadequate because BSEE considered only the estimated impacts of proposed revisions to subpart H and the estimated costs of seven provisions of subpart H. The analysis—and, by extension, the resulting certification of no significant impact—omits any consideration of estimated impacts from BSEE's proposed revision to the BAST rule in subpart A. In addition, several comments assert that by eliminating the longstanding general equivalence of regulatory compliance with BAST, BSEE's proposed revisions to the BAST rule would have significant impacts upon regulated entities, which BSEE had failed to consider, because that change would create uncertainty for regulated entities pertaining to whether their planned and ongoing operations meet BAST.

Response—BSEE does not agree that it failed to comply with the RFA regarding the cost impact on small entities of the proposed revisions to § 250.107(c). As previously explained in part IV.C.2, the proposed and now-final revisions to the BAST language impose no significant new costs on any entity, small or otherwise. The final revisions to § 250.107(c) clarify the intent of the existing regulation and better align the regulatory language with the longstanding BAST language in OCSLA. In addition, the commenters' claim regarding the costs of the proposed deletion of former language equating compliance with BSEE regulations with BAST is moot, since the final rule now includes language maintaining that longstanding regulatory principle.

As stated in previous responses, since the revisions to § 250.107(c) do not establish a new BAST program or new BAST requirements, but rather clarify and incorporate existing baseline statutory and regulatory principles governing BAST compliance, they create no new costs for small entities.[12]

Whether Proposed BAST Rule Constitutes a ''Significant Regulatory Action''

Comment—Commenters asserted that this rule constitutes a ''significant regulatory action'' which should trigger a review by the Office of Information and Regulatory Affairs (OIRA) of its anticipated costs and benefits. The commenters noted that the proposed rule and its supporting documentation indicated that both BSEE and OIRA determined that this rule is not a significant rulemaking under E.O. 12866. Commenters asserted that both the proposed rule and the initial economic analysis considered only the potential costs and benefits of the proposed regulatory provisions of subpart H. Commenters suggested that this analysis—and by extension, the resulting determination that the proposed rule would not be significant—omits any consideration of estimated impacts from BSEE's proposed revision to the BAST rule in subpart A. Commenters also asserted that BSEE omitted the costs arising from the significant uncertainty the proposed BAST rule interjects into the operations and decision making by regulated entities that have long depended upon BSEE's regulations and regulatory process for implementing BAST in their offshore planning.

Response—BSEE does not agree that its and OIRA's determination that this is not a significant rulemaking under E.O. 12866 is incorrect, especially with regard to the revised BAST language. As previously explained in responses to other comments, the revisions to § 250.107(c) do not create a new BAST program or reflect any new BAST determinations, but rather merely clarify and incorporate longstanding baseline statutory and regulatory principles regarding BAST compliance, and, thus, impose no new costs on operators. The concerns related to the loss of certainty provided by regulatory compliance presumptively constituting BAST are likewise mitigated by the revisions BSEE made from the proposed to the final rule.

Definition of BAST

Comment—One commenter suggested that BSEE has acknowledged that technologies already in place are BAST. The commenter also proposed language that recognizes that existing technologies meet the intent of OCSLA.

Response—BSEE does not agree that the commenter's suggested language change is necessary or appropriate. The proposed concept is not consistent with OCSLA or its implementing regulations. Existing BSEE regulations at § 250.105 define BAST as ''the best available and safest technologies that the BSEE Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.'' This existing definition is consistent with the language and intent of OCSLA and clarifies that the Director may make BAST determinations on an industry-wide basis or for different classes or categories of operations based on economic feasibility. BSEE revised the BAST provisions under § 250.107(c) in the final rule to be consistent with OCSLA and, thus, with the existing definition. The revisions also clarify that the Director will determine when to deem specific technology—not already required by BSEE's regulations—to be BAST, using the criteria specified in OCSLA, and that the Director also will determine when to waive the application of BAST to existing operations. Moreover, since OCSLA expressly requires the use of BAST, as determined in accordance with OCSLA, for existing operations whenever

[12] As explained elsewhere in part IV.C.2, any costs associated with BAST waiver requests may be considered part of the economic baseline. Nonetheless, BSEE has included those minimal costs in the final economic analysis and in the Paperwork Reduction Act burden estimate in part V of this document.

practicable, we can conclude that Congress did not view all ''technologies already in place'' or ''existing technologies'' inherently to represent BAST.

How must I install, maintain, and operate electrical equipment? (§ 250.114)

Section summary—This section of the existing regulations requires that areas be classified, and electrical systems installed, in compliance with certain incorporated electrical standards and that employees who maintain such systems have appropriate expertise. BSEE did not propose any changes to this section; however, BSEE has revised the section heading in the final rule to include ''maintain,'' in order to more fully and accurately capture the existing requirements of this section.

Service Fees (§ 250.125)

Section summary—This existing section contains fees charged to operators for services BSEE provides, such as processing various applications. The final rule will revise this section to update the cross-references in paragraphs (a)(5) through (a)(10) to conform to the recodification of § 250.802(e) to § 250.842, as discussed later in this document. The entire table is republished in this final rule for completeness.

Regulatory text changes from the proposed rule—In the final rule, BSEE has revised the fees from proposed § 250.842 in order to reflect the current fee amounts in existing § 250.802(e), some of which have changed since the proposed rule was published. BSEE revised final paragraphs (a)(5) and (a)(6) to clarify that facility visits are pre-production inspections.

Comments and responses—BSEE did not receive any comments on this service fees section.

Documents Incorporated by Reference (§ 250.198)

Section summary—Section 250.198 of the existing regulations contains provisions regarding how BSEE incorporates documents by reference in BSEE's regulations, lists all of the documents BSEE incorporates by reference in part 250, and confirms BSEE's general expectations for compliance with those documents. The requirements for complying with a specific incorporated document can be found where the document is referenced in the regulations, as specified in § 250.198. As proposed, the final rule incorporates by reference one standard (API 570) that had not previously been incorporated in § 250.198, and requires compliance with API 570 in various sections of the proposed rule (as described in part II.B of this document). As proposed and as explained elsewhere, various sections of the final rule require compliance with 8 standards that had previously been incorporated by reference in existing § 250.198; thus, the final rule revises § 250.198, as proposed, by adding the section numbers for those new requirements to the appropriate subparagraphs in § 250.198.

Regulatory text changes from the proposed rule – In the final rule, BSEE has revised proposed paragraph (h)(51) to include references to the incorporation by reference of the identified documents at §§ 250.292 and 250.733. Final paragraph (h)(70) was also revised to include references to the incorporation by reference of the identified documents at §§ 250.730 and 250.833.[13] The references to sections §§ 250.292 and 250.833 were inadvertently omitted in the proposed rule. Similarly, the final rule makes minor, non-substantive punctuation and related changes to paragraphs (h)(93) through (h)(95), which were added to § 250.198 by separate final rules published after this proposed rule.[14] References were also updated in other sections to reflect the most recent reaffirmations of relevant documents.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Standards Already Incorporated in Other Parts of the Regulations

Comment—One commenter observed that some of the standards incorporated by reference into the proposed rule are already incorporated into other parts of the existing regulations.

Response—Standards may be incorporated into multiple parts of the regulations, as when similar equipment may be used for different operations subject to different regulatory provisions. For example, subparts H and I require similar considerations for design; incorporating the same standards in relevant sections of both subparts ensures that the production safety system and the platform or structure are integrated. In other cases, BSEE has decided that the same standards should apply for other reasons. For example, pipelines, which are regulated under subpart J, and certain aspects of production safety systems related to piping, regulated under subpart H, implicate several of the same standards and BSEE has determined that it is important to incorporate each relevant standard in all regulatory sections to which it applies.

Request of BAST Determination for Incorporated Standards

Comment—One commenter requested an explanation of how BSEE determined that each standard proposed for incorporation in the regulations was the best available and safest technology and operating practice for the OCS.

Response—The incorporation of industry standards does not reflect a specific BAST determination by BSEE. The authority to incorporate industry standards into BSEE regulations is separate from the BAST authority. The National Technology Transfer and Advancement Act (NTTAA) mandates that Federal agencies use technical standards developed or adopted by voluntary consensus standards bodies, as opposed to using government-unique standards, where practicable and consistent with applicable law. These criteria for rulemaking are different from those applicable to BAST determinations under OCSLA and § 250.107(c). BSEE follows the requirements of the NTTAA and the relevant guidance in OMB Circular A–119 when incorporating standards into its regulations.

Availability of Standards for Public Review

Comment—Some commenters expressed concern about the availability of the standards incorporated by reference in the proposed rule. They were concerned that many standards are not easily accessible or generally available to the public as part of the rulemaking process or thereafter. One commenter estimates that the public's burden for purchasing the industry standards that were not made available to the public would be approximately $5,900. This amount includes all the standards referenced at § 250.198 that are not available to the public free-of-charge. Some commenters also stated that the public cost burden makes meaningful public participation in rulemaking cost-prohibitive and proposes that BSEE change its process for incorporating standards.

Response—As discussed in part II.C of this document, all standards incorporated by reference in BSEE's regulations are available to view for free

[13] The references to §§ 250.730 and 250.733 are necessary because those sections were added to 30 CFR part 250 as part of the final rule, ''Blowout Preventer Systems and Well Control'' published on April 29, 2016 (81 FR 25888).

[14] Those final rules are the Blowout Preventer Systems and Well Control Rule, at 81 FR 26015, and the Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf Rule, 81 FR 46478, 46560 (July 15, 2016).

at BSEE offices. In addition, the public may view API documents incorporated in BSEE regulations free of charge on API's Web site (*http://www.api.org/publications-standards-and-statistics/publications/government-cited-safety-documents*). Some standards organizations make their standards available for viewing on ANSI's Web page (*http://ibr.ansi.org/Standards/Default.aspx*). In addition, documents from other standards organizations may be purchased directly from those organizations. Standards may be copyright protected under U.S. and international law. Federal law, including the NTTAA, upon which BSEE relies to incorporate industry consensus standards by reference, does not eliminate the availability of copyright protection for industry-developed consensus standards incorporated by reference into Federal regulations.[15] While BSEE works to maximize the accessibility of incorporated documents, and provides directions to where the materials are reasonably available pursuant to Office of **Federal Register** (OFR) requirements, it also must respect the publisher's copyright. OFR's regulations state that, if a proposed rule does not meet the applicable requirements for incorporation by reference, the OFR Director will return the proposed rule to the agency (*see* 1 CFR 1.3); that did not occur here. There is no requirement that such documents be available either online or for free. (*See* 79 FR 66269–72 (Nov. 7, 2014), explaining why OFR declined to include such requirements in its regulations on incorporation by reference.)

The estimate provided by the commenter ($5,900 to purchase the standards that were not made available to the public for this rulemaking) includes standards already incorporated into existing BSEE regulations. The commenter stated that the $5,900 estimate includes all the standards referenced in § 250.198 that are not available to the public free-of-charge. The estimated cost, therefore, includes standards that are not incorporated into subpart H or related to this rulemaking and overstates the costs associated with this rulemaking.

[15] *See, e.g.,* Incorporation by Reference final rule, Office of the Federal Register, 79 FR 66267, 66273 (Nov. 7, 2014) (''[T]he NTTAA [has] not eliminated the availability of copyright protection for privately developed codes and standards that are referenced in or incorporated into federal regulations. Therefore, we cannot issue regulations that could be interpreted as removing copyright protection from IBR'd standards.'')

Conflicts Between Incorporated Standards and BSEE Regulations

Comment—Commenters expressed concern that there is a lack of clarity regarding precedence when a standard conflicts with a regulation. Commenters stated that the regulations should specifically state that wherever BSEE's regulations are more specific or provide more stringent requirements than those listed in an industry standard, BSEE's regulations take precedence.

Response—BSEE has provided clarification, in final § 250.800(d), that if there is a conflict between the standards incorporated through this rulemaking and other provisions of subpart H, the operator must follow the regulations.

Public Review and Comment on Incorporated Standards

Comment—Commenters asserted that: BSEE should go through the process of public review and comment prior to incorporating a new or updated standard: There should be at least a 30-day public review and comment period on proposed rulemakings to update an industry standard; and BSEE should provide a technical support document for that proposed rulemaking showing how BSEE determined the updated standard to be the best available and safest technology and operating practices and explaining why incorporating the industry standard results in a safety improvement.

Response—The commenters' requests as to how BSEE should incorporate industry standards in the future is beyond the scope of this rulemaking. As previously discussed, in this rulemaking BSEE made all of the documents incorporated by reference available for public review in connection with the comment period provided for the proposed rule and continues to make publicly available at its office all of the standards incorporated by reference in the final rule.

In any event, in its rulemakings, BSEE complies with the NTTAA requirement that an agency ''use standards developed or adopted by voluntary consensus standards bodies rather than government-unique standards, except where inconsistent with applicable law or otherwise impractical.'' (OMB Circular A–119 at p. 13). BSEE also complies with the OFR regulations governing incorporation by reference. (*See* 1 CFR part 51.) Those regulations also specify the process for updating an incorporated standard at § 51.11(a), and BSEE complies with those requirements, including seeking approval by OFR for a change to a standard incorporated by reference in a final rule. BSEE generally provides for public notice and comment through proposed rulemaking when incorporating a new standard into its regulations.[16]

Finally, as previously explained, the incorporation of industry standards does not reflect a specific BAST determination by BSEE; those actions derive from separate authorities and are governed by different criteria.

Updating Standards Incorporated in the Regulations

Comment—Commenters suggested that BSEE should: Review all industry standards listed in § 250.198 to eliminate discontinued standards; update standards for which newer versions have been published, if BSEE determines the updated standard version provides BAST and operating practice improvements; and eliminate standards that no longer represent BAST and best operating practices.

Response—This comment, seeking future action by BSEE to amend § 250.198, is also outside the scope of this rulemaking. BSEE reiterates that a decision to incorporate, or revise an existing incorporation of a standard is separate from specific BAST determinations. Nonetheless, BSEE engages in retrospective review of its regulations in accordance with E.O. 13563 and E.O. 13610 ''to ensure, among other things, that regulations incorporating standards by reference are updated on a timely basis . . . .'' (OMB Circular A–119 at p. 4). In fact, BSEE has already begun reviewing many of the standards incorporated in the existing regulations and will provide additional information regarding its review when appropriate. If BSEE decides that some updating of incorporated standards (*e.g.,* by referencing new editions of existing standards, or replacing previously incorporated standards with different standards, or simply deleting outdated standards) is warranted, it will explain its position through future rulemakings, as necessary. Of course, BSEE may also decide, for appropriate reasons, to keep a previously incorporated edition of a standard in the regulations even if there is an updated edition.

Tubing and Wellhead Equipment (§ 250.518)

Section summary—Paragraph (d) of existing § 250.518 requires that subsurface safety equipment be installed, maintained, and tested in

[16] Under certain circumstances, existing § 250.198(a)(2) authorizes BSEE to incorporate a newer edition of an industry standard through a direct final; however, that authority was not exercised in this rulemaking.

compliance with the applicable provisions of subpart H. BSEE proposed to revise this section to include updated cross-references to new section numbers in subpart H.

Regulatory text changes from the proposed rule—BSEE corrected the section number in the final rule to ''§ 250.518,'' since the citation (''§ 250.517'') used in the proposed rule was in error.

Incorrect Section Number

Comment—A commenter pointed out that the proposed revision actually belongs in existing § 250.518.

Response—BSEE agrees and has corrected the section number in the final rule to § 250.518 (Tubing and wellhead equipment).

Tubing and Wellhead Equipment (§ 250.619)

Section summary—Paragraph (e) of § 250.619 of the existing rule requires that subsurface safety equipment be installed, maintained, and tested in compliance with the applicable provisions of subpart H. BSEE proposed to revise this section to include updated cross-references to the new section numbers in subpart H.

Regulatory text changes from the proposed rule—BSEE updated the section number in the final rule to ''§ 250.619'' because the citation used in the proposed rule (''§ 250.618'') was in error.

Incorrect Section Number

Comment—A commenter pointed out that the proposed revisions actually belong in § 250.619, not § 250.618.

Response—BSEE agrees and has corrected the section number to ''§ 250.619'' in the final rule.

General (§ 250.800)

Section summary—This section of the existing regulations established general requirements for the design, installation, use, maintenance, and testing of production safety equipment, including production safety systems to be used in subfreezing climates, to ensure safety and to protect the environment. This section of the final rule retains most of those requirements and further clarifies the design requirements for production safety equipment. In particular, BSEE added a new paragraph (b) to the final rule, as proposed, specifying the industry standard—API RP 14J, Recommended Practice for Design of Risers for FPSs and TLPs—that operators must follow for new production systems on fixed leg platforms. In the final rule, BSEE revised existing paragraph (b) and redesignated it as paragraph (c), which retains the existing requirement that new floating production systems (FPSs) comply with API RP 14J. Existing paragraph (b) also required new FPSs to comply with the drilling and production riser standards of API RP 2RD, Recommended Practice for Design of Risers for FPSs and TLPs; final paragraph (c), as proposed, omits the reference to the drilling standards, but retains the requirement for compliance with the production riser standards of API RP 2RD.

Final paragraph (c), as proposed, also provides examples of FPSs (*e.g.,* column-stabilized-units (CSUs); FPSOs; TLPs; and spars) and revises the existing stationkeeping system requirements for new floating facilities by adding a reference to API RP 2SM, Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring. In addition, BSEE proposed in paragraph (c) to prohibit installation of single bore production risers on floating production facilities beginning 1 year after the publication date of the final rule.

Regulatory text changes from the proposed rule—After consideration of public comments, BSEE removed the proposed provision that would have allowed operators 1 year after publication of the final rule to comply with the prohibition against installing new single bore production risers. Thus, final paragraph (c)(2) now prohibits the installation of single bore production risers from floating facilities as of the effective date of the final rule.

BSEE also added the parenthetical ''(*i.e.,* anchoring and mooring)'' after the word ''stationkeeping'' to final paragraphs (c)(3) and (c)(4) in order to clarify the types of stationkeeping systems for floating production facilities to which those paragraphs apply. Those revisions also clarify that this provision is not intended to regulate the design of the dynamic positioning system (*i.e.,* the propulsion system); rather, they will simply ensure that the potential impacts an anchoring or mooring system could have on an FPS are considered during design of the production process system. (For example, the buoy of a turret-mounted FPS is a structural element of the production system, while the mooring system may also affect the production system.)

Based on public comments, BSEE also added a new paragraph (d) to clarify that if there are differences between the incorporated industry standards and the regulations, the operator must follow the regulations. Finally, BSEE added new paragraphs (e) and (f) to point out that operators may submit requests to use alternate procedures or equipment or for a departure from the subpart H regulations under existing §§ 250.141 and 250.142, respectively.

Comments and responses—BSEE received comments on several issues related to dual bore and single bore risers under this proposed section and responds to the comments as follows:

Dual Bore Production Risers/Prohibition on New Installation of Single Bore Risers

Comment—Some commenters took issue with the requirement for dual barrier production risers, stating that the term ''production riser'' may have several meanings. Commenters asserted that dual barrier production risers do not need to be used when subsea trees are in place, but accepted that dual barrier production risers are appropriate when using dry trees. Commenters also stated that using single barrier production risers downstream from subsea trees is a widely-accepted industry practice and that ''it has generally been considered safe practice to complete wells through [an] outer riser, using mud weight and the outer riser to provide two barriers with a surface blow out preventer having at least two rams.'' Commenters asserted that requiring dual barrier risers downstream from subsea trees would be uneconomical or impossible. Commenters stated that where subsea trees are used, the tree provides a failsafe barrier to the ocean and, thus, that using single barrier risers downstream of subsea trees is a safe and acceptable practice. Commenters asserted that ''a blanket ban on one particular type of riser configuration and operation does not comply with the statutory requirement for BAST or with the industry experience'' and urged BSEE to reconsider the proposed rule.

Response—Final § 250.800(c)(2) only applies to the installation of production risers from new FPSs.[17] The regulations do not require operators to discontinue use of single-bore production risers that are already in place. The prohibition of installation of single bore production risers from new floating production facilities does not apply to single bore pipeline or flowline risers. BSEE does not consider the pipeline or flowline from a subsea tree to the host facility to be a production riser; rather BSEE considers it a pipeline or flowline riser. BSEE recognizes that the use of single bore pipeline or flowline risers is a

[17] The requirements for non-production risers used during drilling and well completion operations are addressed in existing § 250.733(b)(2) and are not addressed here.

widely-accepted practice that allows for cost-effective hydrocarbon production. If there are any questions about what qualifies as a production riser, the operator may contact the appropriate District Manager.

Comment—Several commenters expressed concern about how the prohibition on installation of single bore production risers will affect existing single bore production risers. Commenters asserted that this technology is acceptable in some applications, and that BSEE should allow future uses of single bore production risers in certain circumstances given that such risers may allow for production from reservoirs that would otherwise be uneconomical. Commenters stated that the preamble of the proposed rule did not provide any detail on why BSEE believes this situation to be unacceptable and asked that BSEE provide justification for prohibiting a technology that has not been proven to be problematic. Furthermore, the commenters asked why, if BSEE believes this practice to be unsafe, BSEE would allow this practice to be available for up to a year after the publication of the final rule.

Commenters also recommended revising the regulatory text to confirm that operators can seek relief from the requirements of subpart H where appropriate.

Response—This section of the proposed and final rule does not address drilling, flowline, or pipeline risers; it only addresses single bore production risers installed on FPSs after the effective date of the rule. Moreover, the concerns about the prohibition on installation of single bore risers is academic, since it has been more than 8 years since BSEE approved the installation of any new single bore production risers; thus, in effect, the regulatory prohibition reflects longstanding BSEE policy and industry practice.[18]

As to currently installed single bore risers, neither the proposed nor the final rule prohibits their continued use. Operators may continue to use single bore production risers that are currently installed, although when work is performed through a single bore production riser, it causes wear on the riser, compromising its integrity. Thus, additional precautions for wear protection, wear measurement, fatigue analysis, and pressure testing prior to performing any well work with the tree removed are necessary for currently installed single bore risers. This is consistent with established BSEE policy and past approvals for well operations using currently installed single bore production risers. It is possible to do this work safely if the existing riser is in good shape, but there is no room for error or failures, since a single bore riser has only a single mechanical barrier and the consequences of failure of a single bore riser with open perforations could be serious; that is why BSEE has long required in permitting decisions, and is now codifying the requirement, that operators use dual barrier production risers for new installations.

Regarding the implementation date for the prohibition of single bore risers, BSEE agrees with the commenter that making the prohibition effective in 1 year was not appropriate under the circumstances; thus, BSEE has changed the effective date of this provision in the final rule to be the same as the effective date of the rule. If there is a question about what a single bore production riser is and how this provision applies to a specific situation, the operator may contact the appropriate District Manager.

Further, as suggested by some commenters, BSEE has added new paragraphs (e) and (f) to the final rule to point out that operators may seek approval to use alternate equipment or procedures in lieu of, or request departures from, the requirements of subpart H in accordance with existing §§ 250.141 and 250.142, respectively. Several provisions of the proposed rule included similar language; however, since the alternate compliance and departure provisions apply to all sections of part 250, it is not necessary to cite them expressly throughout the final rule. By including a single reference to §§ 250.141 and 250.142 in final § 250.800, BSEE confirms that those provisions are applicable to all subpart H requirements.

Hazard Analysis For FPSs

Comment—Commenters raised an issue related to proposed paragraph (c), requiring that all new FPSs comply with API RP 14J. Commenters stated that API RP 14J is a guidance document that identifies multiple tools for conducting a hazards analysis on offshore facilities, but noted that the proposed rule did not specify which tool(s) the operator must use to meet BSEE's expectations. Commenters also asserted that operators are already required to conduct a hazards analysis using one of the tools identified in API RP 14J or another recognized document in accordance with subpart S of BSEE's regulations, (*i.e.,* the SEMS regulations). Commenters recommended that BSEE first establish design and construction criteria for new units and then adjust the regulatory language to reflect the multiple tools in API RP 14J. Commenters recommended that BSEE either delete the API RP 14J requirement from this subpart, or revise the language to require operators to conduct a hazards analysis utilizing any one of the methodologies identified in API RP 14J.

Response—BSEE disagrees with the suggested changes to this section. API RP 14J, incorporated in final § 250.800(c) (for FPSs), was already incorporated by reference in former § 250.800(b) for the same types of facilities. Therefore, operators should already be complying with the relevant requirements, and this comment actually suggests eliminating existing regulatory requirements rather than modifying the proposed requirements. The existing and proposed (and now final) requirements are consistent with and complementary to those in the existing subpart S regulations. The operator may use any hazards analysis that satisfies subpart H to meet the requirements under existing § 250.1911 of subpart S; however, final § 250.800(c) will ensure that operators use an appropriate hazards analysis method selected in accordance with the relevant hazards analysis provisions of API RP 14J.[19]

Safety and Pollution Prevention Equipment (SPPE) Certification (§ 250.801)

Section summary—This section of the final rule contains requirements that were contained in § 250.806 of the existing regulations, requiring the installation of certified SPPE on OCS wells or as part of the system associated with the wells. The final rule, as proposed, also contains provisions to clarify that SPPE includes SSVs and actuators, such as those installed on injection wells capable of natural flow as well as BSDVs beginning 1year after the publication date of the final rule. (The installation and use of BSDVs was previously addressed in NTL No. 2009–G36, which clarified that BSDVs have the same function as SSVs and that BSDVs are the most critical component of a subsea system; thus, BSDVs that received approval and were installed in accordance with that NTL should

[18] BSEE also finalized a similar provision as part of the Blowout Preventer Systems and Well Control Final Rule, effective July 28, 2016. (81 FR 25888 (April 29, 2016.)

[19] API RP 14J, section 7.1 states: ''[t]he following sections describe the principal elements of hazards analysis and the various methods available, discuss review procedures to be followed, and outline the guidelines for selection of an appropriate method.''

already be in compliance with the requirements in the final rule.)

This section of the final rule also specifies that BSEE will not allow subsurface-controlled SSSVs on subsea wells and omits the reference to the ANSI/ASME standards found in existing § 250.806 because those standards are outmoded or have been withdrawn. The final rule also provides that SPPE equipment that is manufactured and marked pursuant to API Spec. Q1 will be considered certified SPPE under part 250. Although SPPE that is not manufactured or stamped pursuant to API Spec. Q1 is presumptively non-certified, final § 250.801(c) provides that BSEE may exercise its discretion to accept SPPE manufactured under quality assurance programs other than API Spec. Q1, provided that an operator submits a request to BSEE containing relevant information about the alternative program, that an appropriately qualified third-party verifies the alternative program as equivalent to API Spec. Q1, and that BSEE approves the request. In addition, final paragraph (c) authorizes an operator to request that BSEE accept SPPE that is marked with a third-party certification mark (other than an API monogram).

Regulatory text changes from the proposed rule—In the final rule, BSEE revised proposed paragraph (a)(2) to include BSDV ''and their actuators.'' This is consistent with the requirements for other SPPE and acknowledges that the actuator is an integral part of the valve. BSEE further revised that paragraph to clarify that, for subsea wells, a BSDV is the equivalent of an SSV on a surface well. BSEE also revised proposed paragraph (c) to provide that any requested alternative quality management system must be verified as equivalent by an appropriately qualified entity.

Comments and responses—BSEE received public comments on this section and responds to them as follows:

Quality Assurance Programs

Comment—Commenters expressed concern that proposed § 250.801 would only recognize the quality assurance program in API Spec. Q1 for certified SPPE. Those commenters suggested broadening the coverage of the rule to include International Organization for Standardization (ISO) 9001, ''Quality Management Standards—Requirements'') (2015). Another commenter recommended that the equipment be marked by the manufacturer with the API Monogram as proof of conformance with the proposed requirement.

Response—BSEE evaluated this recommendation and has determined that the proposed quality assurance program requirements under paragraphs (a) and (b) are appropriate and provide sufficient flexibility. Nonetheless, BSEE has revised final § 250.801(c) to clarify that an operator may submit a request to BSEE to accept SPPE manufactured under another quality assurance program as compliant with paragraph (a), provided that an appropriately qualified entity (such as one that meets the criteria of ISO 17021–3, ''Conformity assessment—Requirements for bodies providing audit and certification of management systems—Part 3: Competence requirements for auditing and certification of quality management systems,'' or similar criteria) verifies that the other quality assurance program is equivalent to API Spec. Q1. In addition, although BSEE has decided that a monogram requirement is not necessary, since this provision helps ensure the quality of the SPPE during the manufacturing process, BSEE will consider the marking of SPPE with the API monogram or a similar third-party certification mark, as alternative evidence of conformance with this section.

Definition of BSDV

Comment—One commenter requested clarification of the definition of a BSDV. Another commenter requested that BSEE clarify that only those valves associated with subsea systems qualify as BSDVs.

Response—According to the Barrier Concept (as discussed in BSEE NTL No. 2009–G36), for subsea wells, the BSDV is the surface equivalent of an SSV on a surface well. BSEE has added text to § 250.801(a)(2) in the final rule to clarify this point. Thus, the function of the BSDV is similar to the function of the SSV, and since the BSDV is a critical component of the subsea system, it is appropriate for BSDVs to be subject to the same requirements as SSVs under § 250.801. This also ensures the appropriate level of safety for the production facility. Final § 250.835 states that BSDVs are associated with subsea systems; this point is also emphasized by the revised text in final § 250.801(a)(2).

Certification of SPPE

Comment—Commenters requested clarification as to whether BSEE will deem existing SPPE acceptable, despite new certification requirements, until such equipment can be replaced. A commenter also requested clarification of the estimated impact on the cost and supply of SPPE equipment once ANSI/ASME SPPE–1–1994, ''Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations,'' is no longer acceptable as an SPPE certification program.

Response—Section 250.806 of the existing regulations contained requirements similar to those in proposed § 250.802(d) regarding the use and installation of certified SPPE. Specifically, existing § 250.806 required use of certified SPPE if that SPPE was installed on or after April 1, 1998. However, existing § 250.806 also provided that non-certified SPPE in use as of that date could continue in service unless and until that equipment needed offsite repair, remanufacture or hot work (such as welding). Similarly, final § 250.802(d), as proposed, confirms that operators may continue to use any existing non-certified SPPE already in service unless and until it needs offsite repair, remanufacture or hot work. In addition, since final § 250.801 includes BSDVs as SPPEs (beginning September 7, 2017), the final rule provides that operators have until that date to come into compliance with the certification requirements for any new BSDVs; moreover, under final § 250.802(d), currently installed non-certified BSDVs may remain in service unless and until they require offsite repair, remanufacture or hot work.

The commenter's question about the cost and supply impacts that could occur once ANSI/ASME SPPE–1 was no longer recognized is already moot. That standard was withdrawn by industry in favor of API Spec. Q1 in 2013. Thus, the final rule should not adversely affect SPPE costs or supplies because industry has already evolved in keeping with the change in industry standards from ANSI/ASME SPPE–1 to API Spec. Q1.

Certified vs. Non-Certified SPPE

Comment—One commenter asserted that a report referred to in the proposed rule [20] demonstrates that a certified valve does not perform any better than a non-certified valve, and that BSEE has not demonstrated, through statistics and failure data, justification for the certification requirement. The commenter asserted that the requirement for use of only ''certified'' SPPE is not supported by the referenced

[20] The proposed rule cited a 1999 Southwest Research Institute report, ''Allowable Leakage Rates and Reliability of Safety and Pollution Prevention Equipment'' (Project # 272), funded by MMS in connection with proposed safety system testing. (*See* 78 FR 52250.) That report is available at *https://www.bsee.gov/research-record/tap-272-allowable-leakage-rates-safety-and-pollution-prevention-equipment*.

report and will not provide any greater degree of safety or dependability. The commenter supported BSEE's efforts to work with industry to increase reliability of BSDVs and to promote the use of API standards, but noted that the agency does not recognize API Spec. 6D, ''Specification for Pipeline Valves,'' or ANSI standards used in this service.

Response—BSEE disagrees with the suggestion that certification provides no additional assurance that critical safety equipment will perform as designed. The referenced report was not the only factor considered when developing the proposed SPPE certification requirements. The existing regulations have required use of certified SPPE since April 1, 1998. In developing the new proposed and final certification requirements, BSEE considered the effectiveness of this longstanding requirement, as well as the existence of industry standards (such as ANSI/ASME SSPE–1 and API Spec. Q1) that support the requirement for certification to ensure the quality and effectiveness of this equipment. The only substantive addition to the final rule regarding SPPE certification requirements is that BSDVs will be considered SPPE that must be certified and otherwise conform to final § 250.801. As stated elsewhere, BSEE considers the BSDV on subsea wells to be the equivalent of an SSV on a surface well and it is appropriate to include BSDVs as SPPE under § 250.801.

Moreover, under § 250.804(a)(5) of the existing regulations, USVs were required to meet a zero leakage requirement and to be replaced or repaired if they failed to do so. However, since BSDVs will need to be certified (when required) under final §§ 250.801(a)(2) and 250.802(d), and to meet the zero leakage requirement under final § 250.880(c)(4)(iii), USVs used in connection with BSDVs will no longer be required to do so.

In any event, operators may continue to use existing non-certified SPPE already in service until it requires offsite repair, re-manufacturing, or hot work, at which time the operator must replace the non-certified SPPE with SPPE that conforms to the requirements of final § 250.801.

Regarding the comment on certain standards that were not referenced in the proposed rule, BSEE continually works to review various standards for possible incorporation, including those from API, ANSI, and other standards development organizations. The standards referred to in this comment may be considered in future rulemakings. However, the fact that BSEE does not incorporate by reference a particular standard does not preclude an operator from voluntarily complying with that standard. BSEE presumes that industry follows its own standards, regardless of whether BSEE incorporates them in the regulations.

Expand SPPE Certification Requirements

Comment—A commenter suggested that the proposed SPPE certification requirements be expanded to include all SPPE used for any production systems on the OCS where flammable petroleum gas or volatile liquids are produced, processed, compressed, stored, or transferred, and not be limited to the four types of valves listed in § 250.801(a).

Response—BSEE does not agree that the suggested expansion of the certification requirement is appropriate at this time. The particular SPPE identified in this section is specifically used for controlling the flow of fluids from the wellbore. The other equipment mentioned by the commenter is for processing the fluids, and that equipment has separate design, installation, and maintenance requirements under other subparts of part 250 (*e.g.,* subpart J).

Approval of SPPE not Certified Under API Spec. Q1

Comment—A commenter requested further information regarding the expected duration of BSEE review for SPPE equipment approval based on alternate quality assurance programs; the process by which BSEE will approve SPPE; and whether recertification will be required on a periodic basis.

Response—The time required for BSEE to evaluate SPPE manufactured under other quality assurance programs depends on the type and quality of the information submitted. Under final § 250.801(c), only SPPE manufactured under quality assurance programs other than ANSI/API Spec. Q1 would require approval from BSEE. BSEE will handle each evaluation on a case-by-case basis, but because this is expected to happen infrequently, this process will not create serious delays in approval of such equipment. Recertification of SPPE is not required; however, final § 250.802(b) incorporates standards that require for regular testing of SPPE, and final § 250.802(d) contains provisions addressing when the operator must replace existing equipment with certified SPPE.

Requirements for SPPE. (§ 250.802)

Section summary—The final rule recodifies many of the provisions in existing § 250.806(a)(3) as new § 250.802(a) and (b). Those provisions establish requirements for the valves defined as SPPE in final § 250.801, including requiring that all SSVs, BSDVs, USVs, SSSVs, and their actuators meet the specifications in certain API standards incorporated by reference in the final rule.

Final § 250.802(c) includes a summary of some of the requirements contained in the documents that are incorporated by reference in order to provide examples of those types of requirements. These requirements cover a range of activities affecting the SPPE over the entire lifecycle of the equipment and are intended to increase the reliability of the equipment through a lifecycle approach.

Final § 250.802(c)(1) also requires that each device be designed to function and to close in the most extreme conditions to which it may be exposed; this includes extreme temperature, pressure, flow rates, and environmental conditions. Under the final rule, the operator must have a qualified independent third-party review and certify that each device will function as designed under the conditions to which it may be exposed. Final § 250.802(c) also describes particular SPPE specifications and testing requirements.

BSEE has included a table in final § 250.802(d) to clarify when operators must install SPPE equipment that conforms to the requirements of § 250.801. Under the final rule, non-certified SPPE already in service can remain in service until the equipment requires offsite repair, re-manufacturing, or any hot work, in which case it must be replaced with SPPE that conforms to the requirements of § 250.801.

Final § 250.802(e) requires operators to retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of SPPE until 1 year after the date of decommissioning of the equipment.

Regulatory text changes from the proposed rule—BSEE added actuators to the provisions in this section regarding SSVs, BSDVs, USVs, and SSSVs in order to be consistent with § 250.801 and to emphasize that the actuators are an integral part of the valves; therefore, the same requirements will apply to both the valves and the actuators. BSEE also slightly revised the language in the table in final § 250.802(d) to further clarify the circumstances under which certified SPPE must be used.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Definition of Lifecycle Approach

Comment—Commenters requested clarification of the meaning of ''lifecycle approach.''

Response—Although this term is not used in the regulatory text, the lifecycle approach involves vigilance throughout the entire lifespan of the SPPE, including design, manufacture, operational use, maintenance, and eventual decommissioning of the equipment. This approach considers ''cradle-to-grave'' issues for SPPE and is a tool to evaluate the operational use, maintenance, and repair of SPPE over its lifetime. Addressing the full lifecycle of critical equipment is essential to increasing the overall level of confidence that this equipment will perform as intended in emergency situations. As discussed earlier in part II.B, this concept is currently reflected in several industry standards for SPPE (*e.g.,* API Spec. 6A), and incorporating that concept in the final rule will ensure that it is more consistently followed by operators.

A major component of the lifecycle approach involves the proper documentation of the entire process, from manufacture through the end of the operational limits of the SPPE, which allows for continual improvement throughout the life of the equipment by evaluating mechanical integrity and improving communication between equipment operators and manufacturers.

Requirements for Valves

Comment—A commenter stated that it is dangerous to open a large diameter valve with full differential pressure across the valve's gate and, thus, revisions should be made to the proposed language to allow an arrangement where a smaller valve, at full differential pressure, first opens to reduce the pressure across the larger valve.

Response—BSEE does not agree that the suggested revision is necessary. BSEE does not expect the operator to open a large diameter valve with full differential pressure across the gate. Nothing in this section prohibits use of smaller diameter actuated valves in equalization lines, assuming that the smaller actuated valves can be isolated with a manual valve. This section provides the basic requirements for the functioning of the device, meaning that it has to close under the most extreme conditions to which it may be exposed, but does not specify precisely how that must be done.

Definition of Traceability

Comment—A commenter requested clarification on the meaning of the ''traceability'' requirement in proposed paragraph (c)(5).

Response—Section 250.802(c)(5) requires operators to comply with and document all manufacturing, traceability, quality control, and inspection requirements for SPPE subject to subpart H, including the standards incorporated by reference in the regulations. Traceability refers to the ability to document the installation, maintenance, inspection and other significant events during the ''lifecycle'' of the particular piece of equipment as they relate to the equipment's proper functioning. This includes, for example, documenting the marking of the equipment received from the manufacturer, so the operator can accurately track each piece of SPPE during its useful life. The standards incorporated by reference in final § 250.802(a) and (b) contain specific provisions on traceability.

Use of Independent Third-Parties

Comment—A commenter suggested that independent third-parties may not have the expertise required to conduct the lifecycle analysis on SPPE that was called for in § 250.802(c)(1) of the proposed rule. That commenter also suggested that limiting third-party certifiers to API-approved independent third parties would limit the pool of expertise, which would delay certification. Another commenter requested clarification as to the criteria for establishing whether a third-party reviewer has sufficient expertise and experience to perform the review and certification. That commenter also asked whether third-party reviewers will require periodic reevaluation.

Response—Final § 250.802(c)(1), as proposed, requires the independent third-party to have sufficient expertise and experience to perform the SPPE review and certification. Contrary to one commenter's assumption, however, § 250.802(c)(1) does not limit the pool to API-approved independent third parties.[21] Rather, that section makes operators responsible for ensuring that the third-party reviewers possess the appropriate experience and expertise. Operators currently have extensive experience in the use of independent third-party reviewers to comply with a number of existing regulatory requirements, and operators can use that experience to ensure that a third-party has the qualifications to perform its duties under § 250.802(c)(1). Based on BSEE's experience monitoring compliance with existing third-party requirements, BSEE believes that there is already a sufficient pool of qualified independent third-party reviewers for operators to choose from. Although BSEE does not need to approve third-party reviewers under this section, BSEE may consider the qualifications of independent third-party reviewers, on a case-by-case basis as the final rule is implemented and may, if appropriate, provide additional guidance in the future regarding third-party reviewer experience and expertise.

Finally, § 250.802(c)(1) does not require periodic revaluation of third-party reviewers; however, the operator will be responsible for ensuring that any third-party it employs possesses ''sufficient expertise and experience'' under § 250.802(c)(1) whenever the third-party performs the reviews and certifications required by this section.

Verifying Lifecycle Analysis

Comment—A commenter asserted that it is unclear from the proposed language how BSEE would verify lifecycle analysis without imposing an unwieldy document review process. The commenter suggested that third-party certification is one way to conduct such verification and to ensure compliance with the rule without BSEE reviewing all of the documentation.

Response—BSEE disagrees with the commenter's premise. Section 250.802 of the final rule does not require that documents related to the lifecycle approach be submitted to or reviewed by BSEE. Paragraph (e) of that section requires only that all documents related to the manufacture, installation, testing, repair, redress, and performance of SPPE be retained until one year after the equipment is decommissioned. If BSEE identifies a need to review any specific documentation to verify that the lifecycle approach is being followed in a particular case, it can request that documentation.

Use of Existing Non-Certified SPPE

Comment—A commenter noted that the proposed rule would allow non-certified SPPE to remain in service. The commenter suggested that non-certified SPPE should be replaced over a specified period of time and eventually

[21] The commenter may have confused the requirement in proposed paragraph (c)(3) that SPPE valves be tested by ''API-licensed test agencies'' with the third-party certification requirement in paragraph (c)(1). There is no such limitation in paragraph (c)(1) regarding third-party reviewers. Information from the tests performed by a licensed testing agency under paragraph (c)(3) may, of course, be used by an independent third party in reviewing and certifying SPPE under paragraph (c)(1), although additional documentation may also be necessary.

eliminated completely at offshore facilities.

Response—BSEE does not believe that the commenter's suggested requirement is necessary. The regulation (existing § 250.806(b)(2)) that is being revised and replaced by final § 250.802(d) already required, as of April 1, 1998, that operators replace non-certified SPPE that needed offsite repair, re-manufacturing, or any hot work with certified SPPE. Thus, most existing SPPE is already certified under the existing regulation; this final rule essentially adds BSDVs and their actuators to that certification requirement (beginning September 7, 2017). Moreover, final § 250.802(d) also requires any remaining non-certified SPPE that needs offsite repair, remanufacturing or hot work to be replaced with certified SPPE. In addition, all SPPE must meet specific testing requirements pursuant to final § 250.880. Any existing, non-certified SPPE that fails such tests and that is in need of offsite repairs, remanufacturing, or hot work, must be replaced with certified SPPE pursuant to final § 250.802(d). Existing § 250.806(b)(2) also permitted installation, prior to April 1, 1998, and use of non-certified SPPE only if it was in the operator's inventory as of April 1, 1988, and was included in a list of noncertified SPPE submitted to BSEE prior to August 29, 1988. Thus, BSEE expects that non-certified SPPE will be replaced by certified SPPE over time without the need for the additional requirements suggested by the commenter.

Purpose of SPPE Requirements for BSDVs

Comment—A commenter suggested that the proposed language of § 250.802(a) and (c) was inaccurate, internally inconsistent, and not in agreement with the overall intent of the proposed rule. Specifically, the commenter stated that, although BSDVs are included in paragraph (a), BSDVs are not specifically addressed in the referenced standards, and the rule should instead include a reference to API RP 14H for BSDVs. The commenter also asserted that the intent of the independent third-party language in proposed paragraph (c)(1) was to require no more than a simple certification and marking with the API monogram by the manufacturer, and that requiring an independent third-party to certify functionality of every individual item of equipment would not be achievable.

Response—BSEE does not agree with the commenter's implied assertion that the inclusion of BSDVs in paragraph (a) is inconsistent with the language of that paragraph incorporating API Spec. 6AV1 and API/ANSI Spec. 6A. Although those standards do not expressly refer to BSDVs, their specifications apply to surface valves, which is a term broad enough to encompass BSDVs. In any event, if there is any conflict between any document incorporated by reference and the regulations, the regulations control; thus, the asserted intent of the developer of the standard does not constrain the terms of BSEE's regulations.

Nor does BSEE agree that this section should reference API RP 14H for BSDVs, given that final § 250.836 requires all new BSDVs and BSDVs that are removed from service for remanufacturing or repair to be installed, inspected, maintained, repaired, and tested in accordance with API RP 14H's requirements for SSVs. That standard is also referenced in § 250.880(c)(4)(iii), which requires operators to test BSDVs according to API RP 14H's requirements for SSVs.

BSEE also does not agree with the commenter's concerns regarding the independent third-party requirement in final § 250.802(c)(1). The independent third-party does not guarantee permanent functionality of the SPPE, as implied by the commenter, but certifies that—at the time of certification—the equipment will function as designed under the conditions to which it may be exposed.

Comment—Several commenters requested clarification on the requirement for independent third-party review and certification of SPPE equipment design under proposed § 250.802(c)(1). Specifically, commenters asked whether BSEE will require approval of the use of a particular certified verification agent (CVA), and whether BSEE will accept wholesale certification by a single supplier of all equipment provided by that supplier.

One commenter also requested clarification as to whether requalification testing performed following equipment design changes will be required, and whether requalification testing will apply only to the manufacturer that makes the design changes.

One commenter recommended that, if BSEE keeps the certification requirement in the final rule, then BSEE should extend the 1-year timeframe in § 250.801(a)(2) before BSDVs are considered to be SPPE to 2 years, thereby extending the compliance date for use of certified BSDVs to 2 years after publication of the final rule. Commenters also expressed concern about the costs of replacing, repairing, or remanufacturing existing (non-certified) SPPE and maintaining documentation for SPPE equipment. In particular, commenters asserted that, where no isolation valve exists, installation or replacement of a safety valve would require excessive shutdown time and construction work on lines that have previously contained hydrocarbons. They also suggested that this result would greatly increase the risk of a serious incident from arbitrarily replacing a non-certified valve that cannot be shown to be inferior to a certified valve.

Response—With regard to the comment on CVAs, BSEE does not intend at this time to limit the pool of independent third-party reviewers by approving or requiring particular certification agents. As stated in an earlier response, if warranted, BSEE can review the qualifications of any independent third-party reviewer and may provide additional guidance in the future, if appropriate, regarding third-party certifiers' experience, expertise and independence.

With regard to requalification testing of SPPE, proposed and final § 250.802(c)(4) expressly state that, if there are manufacturer design changes to a specific piece of equipment, requalification testing is required. With regard to whether the proposed requalification testing requirement applies only to the manufacturer that makes a design change, the answer is ''no.'' When read in conjunction with final § 250.802(c)(3), paragraph (c)(4) requires that requalification testing be performed by an API-licensed test agency. Final paragraph (c)(4) specifies, as proposed, that the operator (*i.e.,* ''you''), not the manufacturer, is responsible for having requalification testing performed.

BSEE disagrees with the request to extend the timeframe for BSDVs to meet the SPPE requirements, including the certification requirement. The 1-year timeframe for BSDVs to be considered SPPE is sufficient, especially since paragraph (d)(3) of this section provides that non-certified SPPE (which will include BSDVs 1 year after publication of the final rule) that is already in service need not be replaced with certified SPPE until it requires offsite repair, re-manufacturing, or any hot work.

Most Extreme Conditions

Comment—A commenter requested clarification as to the meaning of ''most extreme conditions'' to which each SPPE device may be exposed and who has the authority to define the term. The commenter recommended that the operator should be responsible for establishing what ''most extreme credible conditions'' means, but that the operator's assumptions should also be subject to validation by the independent third party. The commenter also requested clarification as to how independent third parties should be selected and the timing and triggering requirements for SPPE device certifications.

Response—The operator is responsible for determination and application of the specific wellbore conditions. As with other aspects of operations, the operator is responsible for making reasonable assumptions and must document and explain those assumptions through the application process. An operator is not responsible for ensuring that SPPE is designed to function at conditions that are not reasonably anticipated during production operations. Conversely, an operator is responsible for ensuring that its proposed SPPE is designed to function properly in the conditions that a qualified and prudent OCS operator should reasonably expect to encounter during the production operation.

For the independent third-party, BSEE will not approve or select appropriate parties. However, BSEE may review the qualifications and expertise of an independent third-party if there is an issue concerning an independent third-party's certifications. Operators must have SPPE certified on a per well basis, because each well will have different operating and environmental conditions.

Costs

Comment—BSEE received multiple comments on the costs associated with industry standards incorporated by reference, and notations that the economic analysis fails to identify those costs. These comments included questions on the economic analysis baseline; whether the economic analysis accurately portrays the 1988 final rule and agency regulations; discussion of the costs of new requirements in API 570 for piping system inspection; and the allegation that the agency did not include or analyze the costs associated with proposed §§ 250.800(b), 250.802(b), and 250.841(b).

Response—BSEE included the costs associated with following industry standards as part of the baseline of the economic analysis. Per OMB Circular A–4, which provides guidance to Federal agencies on the preparation of the economic analysis, the baseline represents the agency's best assessment of what the world would be like absent the action. The 1988 final rule is the starting point, and that rule contained a majority of the provisions that are currently found in the regulations.

The baseline should include all practices that reflect existing industry standards and regulations, and that would continue to do so even if the new regulations were never imposed. Industry standards represent generally accepted practices and expectations that are used by the offshore oil and gas industry in their day to day operations. Such standards are industry-developed documents that are written and utilized by industry experts. Thus, even without regulations requiring compliance with the standards, we understand and expect that industry follows these standards to ensure safety and reliability of operations. Therefore, BSEE includes the benefits and costs of utilizing these standards (including API 570) in the economic baseline. This is consistent not only with the guidance provided by OMB Circular A–4, but also with commonly accepted methods within the economic profession and BSEE's approach in previous rulemakings.

The existing subpart H regulations already require compliance with API RP 14J for all new FPSs. Accordingly, costs associated with such compliance are not attributable to this rule. In addition, compliance with API RP 14J is already required in subpart I (§ 250.901(a)(14)) for all platforms. Subpart S also requires hazard analysis under § 250.1911. Although API RP 14J is not specified in § 250.1911, it is an appropriate document to use for compliance with that section in the context of production safety systems. The requirement for hazard analysis is not new; BSEE is only specifying which document to use for certain situations. By following API RP 14J, as incorporated in subpart H, the operator is also complying with the hazard analysis requirement in subpart S (the SEMS regulations) for the relevant systems.

Final § 250.802(b) is based on industry standards (ANSI/API Spec. 14A, *Specification for Subsurface Safety Valve Equipment* and ANSI/API RP 14B, *Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems*). API RP 14C and RP 14E are already incorporated in the existing BSEE subpart H regulations and are not new requirements.

What SPPE Failure Reporting Procedures Must I Follow? (§ 250.803)

Section summary—Final § 250.803 establishes SPPE failure reporting procedures. Section 250.803(a) requires operators to follow the failure reporting requirements contained in section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs, and to follow the requirements in section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs. It requires operators to provide a written notice of equipment failure to BSEE and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. The final rule defines a failure as, ''any condition that prevents the equipment from meeting the functional specification.'' This is intended to ensure that design defects are identified and corrected and that equipment is replaced before it fails.

Final § 250.803(b) requires operators to ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure and that the results and any corrective action are documented. If the investigation and analysis is performed by an entity other than the manufacturer, the final rule requires operators to ensure that the manufacturer and BSEE receive copies of the analysis report.

Final § 250.803(c) specifies that if an equipment manufacturer notifies an operator that it changed the design of the equipment that failed, or if the operator changes operating or repair procedures as a result of a failure, then the operator must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief of BSEE's Office of Offshore Regulatory Programs or the Chief's designee.

Final § 250.803(d) provides the address to which reports required by this section to be submitted to BSEE must be sent.

Regulatory text changes from the proposed rule—BSEE updated paragraph (a) by changing the required written documentation of equipment failure from a ''report'' to a ''notice,'' and adding BSEE as a recipient. In paragraph (b), BSEE increased the timeframe for investigation and failure analysis to 120 days and added a requirement to submit the analysis report to BSEE. The address for BSEE in proposed paragraph (c) for submission of reports to BSEE was moved to new paragraph (d) in the final rule, which also updates the address to reflect BSEE's current location in Sterling, VA. These changes were in response to comments received and will help ensure that BSEE is aware of equipment failures and corresponding investigations and failure analysis.

Comments and responses—BSEE received public comments on this section and responded to the comments as follows:

Timing of Failure Reporting

Comment—One commenter recommended the submission of all failure reporting data to BSEE within 30 days, and that international failures should be included in the analysis. Another commenter suggested that SPPE failure reports be submitted to a third-party organization for review and analysis so that the third party could analyze the information in the failure reports and provide BSEE, operators and manufacturers with assimilated data that would help develop and improve SPPE reliability and SPPE operating best practices.

Response—BSEE agrees with several of the issues raised by these comments and has revised this section in the final rule to require that the written notice of equipment failure, a copy of the analysis report, and a report of design changes or modified procedures be submitted to BSEE as well as to the manufacturer. Specifically, the notice of failure and report of design changes or modified procedures must be provided to the Chief of BSEE's Office of Offshore Regulatory Programs, or to the Chief's designee, and to the equipment manufacturer within 30 days. However, BSEE does not agree that 30 days is a realistic timeframe for the completion of a thorough and meaningful investigation and failure analysis report. Once failure reporting is sufficiently established, BSEE may consider additional reporting requirements. BSEE does not require failure reporting from areas outside the U.S. OCS. BSEE may consider information that is available from operations in other countries, but since would be extremely difficult to ensure consistent reporting of information, at this time, it is unlikely that BSEE would consider it appropriate to consider such information in a formal analysis. In addition, as suggested by a commenter, BSEE may consider designating an appropriate third-party to receive the failure notifications and operators' investigation/analysis reports so that the third-party could analyze the information and provide aggregated data and statistical analyses to industry, BSEE, and the public.

Comment—Commenters suggested that the proposed 60-day timeframe for investigation and failure analysis could be difficult for some manufacturers to meet given their workload. They suggested that there should be some leeway for instances where failure analyses have been requested or are in process, but will not be completed before the 60-day deadline. The commenters also expressed concern that failure or design change reporting may lead BSEE to require all operators to replace a particular model of equipment based on isolated failures of the equipment.

Response—The comment regarding possible difficulties with equipment manufacturers meeting the proposed deadline for failure investigation and analysis is misplaced; the operator is responsible for ensuring the investigation and failure analyses are performed, not the manufacturer. However, BSEE has increased the timeframe to perform the investigation and failure analysis in the final rule to 120 days to accommodate concerns regarding the operator's ability to meet the shorter proposed timeframe. When BSEE receives notification of a design change from the operator, BSEE will work with the operator on a case-by-case basis to ensure that the appropriate actions are taken, including an assessment of whether any equipment changes are warranted by the reported failure(s).

Manufacturers and Failure Reporting

Comment—One commenter stated that the requirement for failure reporting to and from SPPE manufacturers fails to address the reality that a manufacturer may go out of business or be acquired by another firm. The commenter asked what failure reporting procedures must be followed in the event an SPPE manufacturer is no longer in business or is acquired by a different company.

Response—The failure reporting requirements only apply to active businesses. If a manufacturer is no longer in business, the operator may contact BSEE and we will work with the operator on a case-by-case basis. If a business is the subject of a merger or is acquired by another entity, the operator should perform the necessary reporting with the successor company.

Additional Requirements for Subsurface Safety Valves (SSSVs) and Related Equipment Installed in High Pressure High Temperature (HPHT) Environments (§ 250.804)

Section summary—The final rule recodifies existing § 250.807 as final § 250.804. BSEE did not propose any significant revisions to the existing requirements. This section addresses requirements for SSSVs used in HPHT environments. Paragraph (a) specifies the information that the operator must submit to demonstrate that the SSSVs and related equipment can perform in the HPHT environment. Paragraph (b) defines the HPHT environment. Paragraph (c) describes the related equipment that must meet these requirements.

Regulatory text changes from the proposed rule—BSEE updated the section to correct minor formatting errors and changed the label on the pressure rating specified in paragraphs (b)(1) and (2) from pounds per square inch gauge (psig) to pounds per square inch absolute (psia), to be consistent with industry practices.

Comments and responses—BSEE did not receive any comments on this section.

Hydrogen Sulfide (§ 250.805)

Section summary—The final rule will move the requirements found at former § 250.808 to final § 250.805, and reword them for clarity. These provisions pertain to production operations in zones known to contain hydrogen sulfide (H_2S) or zones where the presence of H_2S is unknown. The final rule also adds a new section requiring that the operator receive approval through the DWOP process for production operations in HPHT environments containing H_2S, or in HPHT environments where the presence of H_2S is unknown.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE received a public comment on this section; however, the comment did not include any relevant questions or suggested modifications to the rule.

Dry Tree Subsurface Safety Devices—General (§ 250.810)

Section summary—The final rule recodifies the provisions in existing § 250.801(a) as final § 250.810 in the context of dry tree subsurface safety devices (final § 250.825 accomplishes a similar recodification for wet trees) and restructures the section for clarity. This section establishes general requirements for subsurface safety devices used with dry trees. All tubing installations open to hydrocarbon-bearing zones must have safety devices that will shut off flow in an emergency situation. It includes a list of subsurface safety devices. The final rule also adds a requirement to install flow couplings above and below subsurface safety devices.

Regulatory text changes from the proposed rule—In response to comments, BSEE revised this section to remove the designation of flow couplings as a safety device, but still requires the installation of flow couplings above and below the subsurface safety device. Flow couplings prevent wear and reduce the effects of turbulence on SSSV performance and are considered to be an integral part of the tubing string. However, they must be installed, as provided for in API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, which is incorporated by reference in other provisions of this final rule (*e.g.,* §§ 250.802(b), 250.803(a), 250.814(d)) and existing BSEE regulations.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Fail-Safe Valves

Comment—A commenter suggested that BSEE should revise the rule language to clarify that surface-controlled SSSVs are fail-safe automatic valves, and these valves are installed at a fail-safe setting depth that allows for automatic closure under worst-case hydrostatic conditions.

Response—No changes are necessary. The regulations require operators to follow API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. This standard is incorporated in existing subpart H regulations, as well as in this final rule. The provisions of API RP 14B are consistent with the commenter's suggestions. In addition, there are specific requirements for SSSVs throughout subpart H and specific testing requirements under § 250.880.

Flow Couplings

Comment—A commenter suggested removing language referencing flow couplings from all sections requiring certification of subsurface safety devices as flow couplings are not safety devices. The commenter also recommended that BSEE incorporate by reference API Spec. 14L, Specification for Lock Mandrels and Landing Nipples.

Response—BSEE agrees with the commenter that flow couplings should not be considered a safety device. BSEE updated the section's introductory paragraph to clarify that flow couplings must be installed above and below the subsurface safety device and removed the reference to a flow coupling as part of the subsurface safety device. BSEE continually considers relevant standards for incorporation, but does not always decide to incorporate a specific standard into the regulations. In this case, the design of equipment that the document covers (lock mandrels and landing nipples) are addressed with tubing design in subparts E and F of the existing regulations. Flow couplings prevent wear and reduce the effects of turbulence on SSSV performance and are considered an integral part of the tubing string.

Specifications for SSSVs—Dry Trees (§ 250.811)

Section summary—The final rule recodifies former § 250.801(b) as § 250.811 with respect to SSSVs used with dry trees. It also updates the internal cross-references to the new provisions of subpart H. This section establishes general requirements for all SSSVs, safety valve locks, and landing nipples, requiring this equipment to conform to the requirements in final §§ 250.801 through 250.803.

Regulatory text changes from the proposed rule—BSEE revised this section by removing flow couplings from the equipment regulated as part of the SSSVs. These changes were made based on comments received to clarify that flow couplings are not considered SPPE. BSEE also removed the reference to approval of alternate procedures or equipment under § 250.141. That provision and its associated procedures are generally available with respect to operations under part 250, so it is unnecessary to specifically reference it here.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Flow Couplings

Comment—A commenter suggested that the language indicating that "flow couplings" must conform to the SPPE requirements should be revised. The commenter noted that there are no API or industry standards for flow couplings as they are not safety devices, but rather a manufacturer specific item of equipment. The commenter also stated that flow couplings are not identified as SPPE in proposed §§ 250.801 through 250.803 and recommended removal of the reference to flow couplings.

Response—BSEE agrees with the commenter that flow couplings should not be considered a safety device. However, they must be installed, as provided for in API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. This document is incorporated by reference in this rulemaking in final § 250.802(b) and existing BSEE regulations. Flow couplings prevent wear and reduce the effects of turbulence on SSSV performance and are considered an integral part of the tubing string. BSEE revised this section to remove the reference to flow couplings and suggestion that they are a safety device.

Surface-Controlled SSSVs—Dry Trees (§ 250.812)

Section summary—The final rule recodifies existing § 250.801(c) as final § 250.812 for purposes of establishing requirements for surface-controlled SSSVs when using dry trees. A change from current regulations will require operators to receive BSEE approval for locating the surface controls for SSSVs at a remote location. Operators must request and receive BSEE approval to locate surface controls at a remote location in accordance with § 250.141, regarding alternate procedures or equipment.

Regulatory text changes from the proposed rule—BSEE did not make any changes to this section.

Comments and responses—BSEE did not receive any comments on this section.

Subsurface-Controlled SSSVs (§ 250.813)

Section summary—The final rule recodifies the requirements of existing § 250.801(d)—regarding standards for obtaining approval of subsurface-controlled SSSVs—as final § 250.813. It rewrites the existing provision using plain language and removes one previously recognized basis for using subsurface-controlled SSSVs.

Regulatory text changes from the proposed rule—BSEE updated the section with minor formatting changes and replaced BSEE with District Manager to clarify where to direct a request for approval to equip a dry tree well with an SSSV that is controlled at the subsurface in lieu of an SSSV that is controlled at the surface.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Require Surface-Controlled SSSVs

Comment—A commenter recommended eliminating the portion of § 250.813 that allows operators to install a subsurface-controlled SSSV instead of pulling the well tubing and installing the preferred surface-controlled SSSV or, at a minimum, the commenter recommended revising the rule to set a time limit for installation of the preferred surface-controlled SSSV, rather than allowing the operator to produce the well indefinitely without making this change.

Response—No changes to the regulation are needed. Requiring installation of an SSSV that is surface-controlled within a specific timeframe may cause an increase in the number of wells that are prematurely abandoned, due to the costs involved with pulling and replacing tubing. This would raise concerns about conservation of resources. The rule requires installation of a surface-controlled SSSV if tubing is removed and reinstalled.

Design, Installation, and Operation of SSSVs—Dry Trees (§ 250.814)

Section summary—The final rule recodifies existing § 250.801(e) as § 250.814, perpetuating standards for the design, installation, and operation of SSSVs with dry trees. The final rule rewords the existing regulation for plain language and clarity. In final § 250.814(b), BSEE incorporated the definition of routine operations from the definitions section at § 250.601 and added a reference to § 250.601 for more examples of routine operations.

Regulatory text changes from the proposed rule—BSEE reversed the order of proposed paragraphs (b) and (c) for greater clarity as to how the requirements in those paragraphs complement each other. BSEE updated final paragraph (d) to include a reference to SSSV testing at § 250.880. This change was based on comments suggesting that BSEE clarify that those testing requirements apply to SSSVs. BSEE also removed the reference to §§ 250.141 and 250.142 from paragraph (a). Those provisions and their associated procedures are generally available with respect to operations under part 250, so it is unnecessary to specifically reference them here. The approval of alternate setting depth under final § 250.814(a) will be considered on a case-by-case basis.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

SSSV Testing

Comment—A commenter recommended that BSEE revise this section to include: A semi-annual SSSV testing interval in the proposed requirement at § 250.880; a requirement that no leakage during valve testing be detected as evidenced by a stabilized, flat-line pressure response verifying that a well is completely shut-in and isolated; a requirement that an operator notify BSEE of valve testing such that it can send inspectors to observe testing; a requirement that the operator report valve failures to BSEE; and immediate shut-in of wells after a failed test or indication of a failed SSSV.

Response—The regulatory testing requirements for SSSVs under § 250.880, in addition to the testing provisions in API RP 14B, are adequate. SSSVs are part of a closed system contained within the tubing. This system is designed to minimize oil spills by stopping the flow within the tubing in the event that the riser is damaged. BSEE revised this section to reference SSSV testing requirements in § 250.880, clarifying that those testing requirements apply to SSSVs. BSEE conducts regular inspections of facilities. During the inspections, a full review of all testing and maintenance records is usually conducted. BSEE can require the operator to test the SSSV and BSEE may witness the testing during routine inspections, however this authority does not need to be specified in § 250.814.

Subsurface Safety Devices in Shut-In Wells—Dry Trees (§ 250.815)

Section summary—The final rule recodifies existing § 250.801(f) as § 250.815 for the context of dry trees, and rewrites it in plain language. This section provides operators with options on how to isolate a well, whether prior to initial production or after being shut-in for a period of 6 months. BSEE did not propose any substantive changes to the existing requirements for subsurface safety devices in shut-in wells using dry trees.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section in the final rule.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Alternate Setting Depths

Comment—A commenter recommended revising proposed §§ 250.814 and 250.815 to specify the alternate setting depth requirements for wells installed in permafrost areas, or wells subject to unstable bottom conditions, hydrate formation, or paraffin problems.

Response—Setting depth is based on site specific conditions. Specifying a single setting depth may not adequately ensure the integrity of the well under all applicable scenarios and environmental conditions. Final §§ 250.814(a) and 250.815(b) allow the District Manager to address the particular circumstances presented in setting depths for wells in areas of permafrost, unstable bottom conditions, hydrate formation, or paraffin problems.

Subsurface Safety Devices in Injection Wells—Dry Trees (§ 250.816)

Section summary—The final rule recodifies existing § 250.801(g) as final § 250.816, and rewrites it in plain language. This section requires operators to install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells, unless the District Manager determines that the injection well is incapable of natural flow. BSEE did not propose any substantive changes to the existing requirements for subsurface safety devices in injection on dry tree wells.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section in the final rule.

Comments and responses—BSEE did not receive any comments on this section.

Temporary Removal of Subsurface Safety Devices for Routine Operations (§ 250.817)

Section summary—The final rule recodifies existing § 250.801(h) as final § 250.817, with the title of the section changed for clarity and the text rewritten for plain language. It addresses how operators must ensure safety if they temporarily remove certain subsurface safety devices to conduct routine operations, *i.e.,* operations that do not require BSEE approval of a Form BSEE–0124, Application for Permit to Modify (APM). BSEE did not propose any substantive changes to the existing requirements for the temporary removal of subsurface safety devices for routine operations.

Regulatory text changes from the proposed rule—In final § 250.817(c), BSEE added the term ''support vessel,'' as another option for attendance on a satellite structure.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Support Vessel

Comment—A commenter asserted that is not clear what purpose is served by the proposed requirement to have a support vessel in attendance if an SSSV is inoperable. The commenter suggested revising the language to remove the reference to support vessels.

Response—No changes are necessary. For a well on a satellite structure, the support vessel is intended to give personnel an escape route in the event of an emergency. If a support vessel is not on site and SSSV is removed, the operator must install a pump-through plug.

Additional Safety Equipment—Dry Trees (§ 250.818)

Section summary—The final rule recodifies existing § 250.801(i) as final § 250.818, addressing additional safety equipment to be used with dry trees. The final rule rewrites the existing provision for plain language, with no significant revisions.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE did not receive any comments on this section.

Specification for Surface Safety Valves (SSVs) (§ 250.819)

Section summary—The final rule recodifies the portion of former § 250.802(c) related to wellhead SSVs and their actuators as final § 250.819. The final rule rewrites the provision for plain language and updates the cross-referenced provisions, but makes no substantive change. BSEE recodified the portion of existing § 250.802(c) related to USVs as § 250.833 in the final rule. This section requires all wellhead SSVs and their actuators to conform to the requirements specified in §§ 250.801 through 250.803.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Valve Testing Requirements

Comment—A commenter recommended that BSEE include or incorporate by reference a separate section on valve testing requirements in this section. Existing regulations require SSVs for each well that uses a dry surface tree. The proposed regulations would require compliance with API RP 14H. API RP 14H provides for periodic valve testing at an unspecified frequency. The commenter supported the monthly testing requirement in § 250.880 for this valve and asserted that such a critical valve used to isolate a well in the event of abnormal well conditions or an emergency should not leak at all. Additionally, the commenter recommended requiring the operator to notify BSEE immediately if a valve fails or does not pass a test and to shut in the well until the valve is repaired or replaced.

Response—Section 250.819 in the final rule requires conformance with § 250.803, which addresses failure reporting to BSEE for SSVs. BSEE may request additional failure data if necessary. To clarify the testing requirements for SSVs, BSEE revised the final rule in § 250.820 to reference § 250.880. There is no need to repeat that reference here. The failure reporting requirements follow industry standards as required in final § 250.803. Under final § 250.880(c)(2)(iv), operators must test SSVs monthly and if any gas and/or liquid fluid flow is observed during the leakage test, the operator must immediately repair or replace the valve. API RP 14H allows for some leakage during this test, however, in the final rule, BSEE requires no gas and/or liquid flow during the leakage test. As previously stated, when there is a difference between the regulations and the incorporated standards, the operator must follow BSEE's regulations.

Use of SSVs (§ 250.820)

Section summary—The final rule recodifies the portion of existing § 250.802(d) related to the use of SSVs as § 250.820. The final rule rewrites the provision for plain language and clarity, but makes no substantive change. This section requires operators to follow API RP 14H for the installation, maintenance, inspection, repair, and testing of all SSVs and includes requirements if the SSV doesn't operate properly or if any gas and/or liquid fluid flow occurs during the leakage test. The portion of the existing § 250.802(d) related to USVs is recodified as final § 250.834.

Regulatory text changes from the proposed rule—BSEE updated the section by adding ''gas and/or liquid'' to clarify the reference to fluid flow observed during the leakage test, and by adding a specific reference to such testing ''as described in § 250.880.'' BSEE added this citation to emphasize that there are specific SSV testing requirements in § 250.880.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Testing References

Comment—A commenter stated that the proposed rule did not refer to the testing requirements specified for SSVs as described in proposed § 250.880. The commenter recommended that a reference to § 250.880 should be included in § 250.820.

Response—BSEE revised this section to include the recommended reference to § 250.880.

Emergency Action and Safety System Shutdown—Dry Trees (§ 250.821)

Section summary—The final rule recodifies existing § 250.801(j) as § 250.821, addressing actions that must be taken in response to emergency situations. BSEE clarified the existing reference to storms as an example of an emergency by adding a reference to a National Weather Service-named tropical storm or hurricane because not all impending storms constitute emergencies. BSEE also added a requirement that operators shut-in oil wells and gas wells requiring compression in the event of an emergency. This final rule also incorporates the valve closure times for dry tree emergency shutdowns from existing § 250.803(b)(4)(ii), with an added reference to §§ 250.141 and 250.142 with respect to obtaining District Manager approval.

Regulatory text changes from the proposed rule—BSEE edited paragraph (a)(2) to clarify the requirements and to define a shut-in well. The content was not otherwise revised but was rearranged. BSEE also removed the reference to §§ 250.141 and 250.142 from paragraph (a)(2)(ii). Those provisions and their associated procedures are generally available with respect to operations under part 250, so it is unnecessary to reference them here. BSEE also removed the reference to the subsea field found in proposed paragraph (b).

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Emergency

Comment—A commenter requested clarification as to what constitutes an ''emergency'' that will require oil wells and gas wells requiring compression to be shut-in.

Response—There a number of different types of emergencies that could necessitate the shut-in of production. The example provided in this section is a specific named storm, and shut-in will be associated with the anticipated storm path. Any number of other emergency circumstances may likewise preclude the safe continuation of production and require shut-in pursuant to this provision. If there are any questions or concerns about whether a particular circumstance requires shut-in, the operator may contact the appropriate District Manager for guidance.

Storm Timers

Comment—A commenter requested clarification that BSEE will not allow oil wells and gas wells requiring compression to flow on hurricane or storm timers, and that they must be shut-in before personnel evacuate.

Response—No changes are necessary based on this comment. The regulations set specific requirements for valve closure timing based on the actuation of an ESD or the detection of abnormal conditions. The regulation does not allow operators to use timers to delay the valve closure. In addition, operators must include emergency response and control in their SEMS program under § 250.1918; this should include evacuation and shut-in procedures.

Impending Named Tropical Storm or Hurricane

Comment—A commenter requested clarification as to the meaning of ''impending named tropical storm or hurricane'' and asks whether there will be some cases in which a storm or other meteorological event will not require shut-in.

Response—The description of an impending named tropical storm is one example of an emergency situation when BSEE would require operators to shut-in their wells. In this example, the need for shut-in will be determined by the anticipated storm path and whether it threatens to impact the relevant production operations. The determination as to whether to shut-in a specific facility during a storm event is based on a number of factors, including the proximity of the facility to the storm path, the anticipated wind strength and waves heights, and the design of the facility. The operator must address emergency response and control in its SEMS program, under § 250.1918; this should include the conditions for shut-in and evacuation.

Subsea Fields

Comment—A commenter noted that the language in this section is specific to dry tree SSVs, but also noted that the proposed text mentions ''subsea fields.'' The commenter recommended deleting the reference to ''subsea fields.''

Response—BSEE agrees with the comment, and removed ''or subsea field'' from paragraph (b) in the final rule.

Subsea Tree Subsurface Safety Devices—General (§ 250.825)

Section summary—Final § 250.825(a) was derived from existing regulations under § 250.801(a) for subsurface safety devices on subsea trees. (Final § 250.810 similarly recodifies the existing regulatory requirements for dry trees.) This section of the final rule restructures the existing requirements and revises them for greater clarity and to use plain language. The final rule adds a requirement to install flow couplings above and below the subsurface safety devices, and removes the exception for wells incapable of flow. The final rule also adds a requirement to test all valves and sensors after installing a subsea tree and before the rig or installation vessel leaves the area.

Regulatory text changes from the proposed rule—BSEE revised final paragraph (a) to require the installation of flow couplings above and below the subsurface safety device and to remove the reference to a flow coupling that suggested it is part of the subsurface safety device. These changes were made based on comments received to clarify the use of flow couplings. BSEE also removed the reference to §§ 250.141 and 250.142. Those provisions and their associated procedures are generally available with respect to operations under part 250, so it is unnecessary to specifically reference them here.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Subsea Trees in the Arctic

Comment—A commenter stated that it is unclear whether proposed § 250.825 would prohibit subsea trees in Arctic operations due to the lack of a provision regarding setting depths in Arctic conditions. If allowed, the commenter recommended that BSEE specify in the regulation the allowable conditions and BSEE explain why the subsea trees would be BAST.

Response—All proposed oil and gas production operations on the OCS are required to have production safety equipment that is designed, installed, operated, and tested specifically for the surrounding location and environmental conditions of operation prior to approval. Under § 250.800(a), the final rule requires all oil and gas production safety equipment to be designed, installed, used, maintained, and tested to ensure the safety and protection of the human, marine, and coastal environments. BSEE understands that the Arctic may have unique operating conditions, however this rulemaking is not Arctic-specific. Although this final rule is intended to address production safety systems in all OCS regions, there are provisions that require the operator to address Arctic-related issues. For example, § 250.800 of the final rule requires operators to use equipment and procedures that account for floating ice, icing, and other extreme environmental conditions for production safety systems operated in subfreezing climates. In addition, BSEE may address Arctic-specific issues through a variety of mechanisms including separate rulemakings, guidance documents, or on a case-by-case basis. As previously explained in response to comments on § 250.107(c), BSEE is not making a BAST determination in this rulemaking, as a whole or for any specific provisions.

Departures

Comment—A commenter recommended that the waiver (departure) provisions of § 250.825(b) should be removed from the proposed rule as BSEE does not specify under what circumstances it would allow the installation of subsea tree valves and sensors without testing all the subsea tree valves and sensors. If BSEE does not agree to eliminate the waiver language from the proposed rule, the commenter requested that BSEE explain under what circumstances it would approve a subsea tree to be installed without testing all the subsea tree valves and sensors, and what criteria would be used in BSEE's decision making.

Response—As discussed previously, BSEE has removed the proposed language referring to departure requests under § 250.142 from the final rule. However, the operator may still submit a departure request related to the requirements of this section or any other requirement in the regulations. The provision for departure requests applies to any of the regulations under part 250, which does not need to be specified in individual sections.

Flow Couplings

Comment—A commenter recommended that BSEE not require ''flow couplings'' to conform to SPPE requirements since they are not a safety device and there are accordingly no API or industry standards for flow couplings. The commenter also noted that flow couplings are not identified as SPPE in §§ 250.801 through 250.803. The commenter asserted that flow couplings are not safety devices, but rather heavy-walled couplings used in conjunction with some down-hole safety device applications.

Response—BSEE agrees with the commenter that flow couplings should not be considered a safety device. However, they must be installed, as provided in API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. This document is incorporated by reference in this rulemaking and existing BSEE regulations. Flow couplings prevent wear and reduce the effects of turbulence on SSSV performance and are considered an integral part of the tubing string. BSEE revised this section to remove the inclusion of flow couplings as a safety device, but added a requirement to install flow couplings above and below the subsurface safety device.

Valve Testing

Comment—A commenter asserted that it is unclear whether proposed paragraph (b) requires the testing of all of the valves and sensors on the subsea tree, in addition to the SSSV, or only those valves that are designated as USVs, and the related pressure test sensors. The commenter noted that § 250.880(c)(4) establishes that these valves must pass the applicable leakage test prior to departure of the rig or installation vessel.

Response—Under this section the operator must test all of the valves and sensors associated with the subsurface safety devices before the rig or installation vessel leaves. If the valve was tested and passed after installation of the subsea tree, then that test is valid and the operator does not have to test again until required to conduct valve testing at regular intervals under § 250.880.

Specifications for SSSVs—Subsea Trees (§ 250.826)

Section summary—Final § 250.826 recodifies provisions from existing § 250.801(b) pertaining to surface-controlled SSSVs, safety valve locks, and landing nipples for subsea tree wells. Since BSEE does not allow subsurface-controlled SSSVs on wells with subsea trees, they are not covered by this provision. The final rule also updates the internal cross-references to the new provisions of subpart H.

Regulatory text changes from the proposed rule—BSEE revised the section by removing ''flow couplings.'' This change was made based on comments received and to clarify that flow couplings are not SPPE.

Comments and responses—BSEE received one comment on this section and responds to the comment as follows:

Flow Couplings

Comment—A commenter asserted that ''flow couplings'' need not conform to the SPPE requirements since there are no API or industry standards for flow couplings and they are not a safety device. The commenter also noted that flow couplings are not identified as SPPE in §§ 250.801 through 250.803.

Response—BSEE agrees with the comment that flow couplings should not be considered a safety device and revised this section to remove the inclusion of flow couplings as a safety device. However, they must be installed, as provided for in API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. This document is incorporated by reference in this rulemaking in final § 250.802(b) and existing BSEE regulations. Flow couplings prevent wear and reduce the effects of turbulence on SSSV performance and are considered an integral part of the tubing string.

Surface-controlled SSSVs—Subsea Trees (§ 250.827)

Section summary—This section was derived from provisions in existing § 250.801(c), and rewritten for clarity and plain language to address requirements for surface-controlled SSSVs for wells with subsea trees. It requires operators to equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV. The final regulations require that surface controls for SSSVs for wells with subsea trees be located on the host facility.

Regulatory text changes from the proposed rule—BSEE revised this section for plain language and to clarify that operators must locate the surface controls for SSSVs associated with subsea tree wells on the host facility instead of on the site or at a remote location.

Comments and responses—BSEE received one comment on this section and responds to the comment as follows:

Comment—A commenter stated that it is not clear how to interpret the proposed ''on site'' requirement with respect to surface controls for subsea wells.

Response—BSEE agrees that the proposed language was potentially unclear and revised this section in the final rule to clarify that the surface controls must be located on the host facility.

Design, Installation, and Operation of SSSVs—Subsea Trees (§ 250.828)

Section summary—The final rule recodifies the provisions found at existing § 250.801(e) as final § 250.828, with changes made for clarity and plain language and to reflect that this section covers subsea tree installations. This section requires operators to design, install, and operate SSSVs to ensure reliable operation and establishes that a well with a subsea tree must not be open to flow while an SSSV is inoperable.

Regulatory text changes from the proposed rule—The final rule changed the language in proposed paragraph (a)—regarding alternate setting depths—from referring to requests for use of alternate procedures under existing § 250.141 to refer instead to approval of alternate depths by the District Manager on a case-by-case basis. This revision better aligns this section with final § 250.814(a) and with the language in the existing regulation.

BSEE also revised final paragraph (b) to clarify that the well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM. The final rule also revised paragraph (c) by adding a reference to § 250.880 for additional SSSV installation, maintenance, repair, and testing requirements.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Inoperable SSSVs

Comment—A commenter recommended that BSEE include language requiring operators to shut-in a well if an SSSV is inoperable as well as language eliminating the possibility of an exception to this requirement.

Response—BSEE does not agree with the suggestion that it should never allow exceptions to this shut-in provision. There may be times where an exception to this provision is warranted and appropriate. However, the operator must request an exception from BSEE in an APM, provide justification for that exception, and secure BSEE approval.

Temporary Flow During Routine Operations

Comment—A commenter suggested that BSEE should add language to this section that allows for temporary flow during routine operations and well troubleshooting. The commenter recommended revising proposed paragraph (b) to read, ''The well must not be open to flow while an SSSV is inoperable once the subsea tree is installed or BSEE has approved the specific operation that requires flow with an inoperable SSSV.''

Response—No changes are necessary. BSEE does not consider flowback of a subsea well through production equipment that has not been approved by BSEE to be a routine operation. Existing § 250.605 statesthat the operator cannot commence any subsea well-workover operations, including routine operations, without written approval from the District Manager. Temporary flowback of a subsea well may involve the use of non-dedicated production equipment, or production equipment installed on a drilling rig, neither of which is part of the normal production flow path for the well. However, final § 250.828(b) provides that the operator must request an exception from BSEE in an APM and secure BSEE approval.

Measuring Leakage in a Subsea Well

Comment—A commenter asserted that the formula provided in this section cannot be used for any well other than a dry gas well and that there is no method to measure the leakage in a subsea well. The commenter stated that subsea well leakage must be calculated and may vary with tree configuration or tree (USV) valve leakage or failure.

Response—BSEE does not agree that the formulas required by this section, through incorporation of API RP 14B, are inappropriate for subsea wells. API RP 14B describes the required testing procedures, including any formulas that are needed for calculating leakage rates. If the operator has additional questions about calculating a particular leakage rate, the operator can contact the appropriate District Manager.

SSSV Testing

Comment—A commenter stated that there are multiple ways to test an SSSV in a subsea well, and that it is not necessarily the case that the test procedure will be as outlined in Annex E of API RP 14B. The commenter recommended modifying the proposed language to indicate that there are acceptable alternative test methods. The commenter also stated that the proposed rule does not directly refer to the testing requirements specified for subsurface safety equipment as described in § 250.880 and suggested adding a reference in final § 250.828(c) to § 250.880.

Response—BSEE agrees with the suggestion to add a reference to § 250.880 for SSSV testing in final § 250.828(c) and has done so. However, it is not necessary to add the suggested language regarding acceptable alternative methods, since an operator may submit a request to the District Manager to use an alternate test procedure under existing § 250.141.

Subsurface Safety Devices in Shut-in Wells—Subsea Trees (§ 250.829)

Section summary—This section recodifies the requirement under existing § 250.801(f) for subsurface safety devices on shut-in subsea tree wells. Operators must equip new completions that are perforated but not placed on production, as well as completions shut-in for a period of 6 months, with a pump-through-type tubing plug, an injection valve capable of preventing backflow, or a surface-controlled SSSV, whenever the surface control has been rendered inoperative. The final rule also clarifies when a surface-controlled SSSV is considered inoperative. BSEE included this clarification because the hydraulic control pressure to an individual subsea well may not be able to be isolated due to the complexity of the hydraulic distribution of subsea fields.

Regulatory text changes from the proposed rule—BSEE made minor revisions to this section in the final rule, such as removing ''BSEE'' from before ''District Manager.'' BSEE also slightly revised the final language to be more consistent with the language of final § 250.815, and removed an unnecessary cross-reference to § 250.141.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Maintaining, Inspecting, Repairing, and Testing SSSVs

Comment—A commenter recommended revising the proposed language to require operators to maintain, inspect, repair, and test all SSSVs in accordance with the Deepwater Operations Plan (DWOP) or API RP 14B. The commenter also suggested removing proposed § 250.829(a)(3)(ii) since the reference pressure sensor is normally internal to the subsea control module, used for housekeeping only, and it may not be available to the topside system.

Response—The commenter's first concern is addressed in § 250.828(c) of the final rule, which requires compliance with the DWOP and API RP 14B. It is not necessary to restate those requirements here. With respect to the commenter's second concern, BSEE understands that there may be situations where another approach would be appropriate and, in such cases, the operator may request approval to use an alternate procedure under § 250.141.

Subsurface Safety Devices in Injection Wells—Subsea Trees (§ 250.830)

Section summary—This section was derived from existing § 250.801(g), rewritten in plain language, and modified to require operators to install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells, unless the District Manager determines that the well is incapable of natural flow. The substance of final § 250.830 for subsea tree wells is similar to the regulatory sections pertaining to final § 250.816 for dry tree wells. BSEE also consolidated similar provisions from existing § 250.801 to improve readability and understanding of the final rule.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes in the final rule to the proposed section.

Comments and responses—BSEE did not receive any comments on this section.

Alteration or Disconnection of Subsea Pipeline or Umbilical (§ 250.831)

Section summary—This new section codifies policy and guidance from existing BSEE Gulf Of Mexico Region NTL No. 2009–G36, ''Using Alternate Compliance in Safety Systems for Subsea Production Operations.'' BSEE intends to rescind this NTL and remove it from the BSEE Web page after the effective date of the final rule. The final rule states that, if a necessary alteration or disconnection of the pipeline or umbilical of any subsea well would affect an operator's ability to monitor casing pressure or to test any subsea valves or equipment, the operator must contact the appropriate District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing.

Regulatory text changes from the proposed rule—This section was revised by removing the word ''BSEE'' before ''District Office'' for consistency with other sections of the final rule and because it was superfluous.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Pipelines

Comment—A commenter stated that this section is unnecessary because the process to repair or modify a subsea pipeline must be approved by BSEE's GOM Regional Pipeline Section.

Response—BSEE disagrees with the comment. Without an umbilical, the operator is unable to monitor casing pressure and test USVs. The existing pipeline regulations (subpart J) do not address the issues related to testing of the valves or the monitoring of casing pressure that are relevant and necessary to this rulemaking under subpart H. The operator needs to test these valves for functionality and leakage rate, and be able to monitor for sustained casing pressure. The physical alteration or disconnection of the subsea flowline system, including the umbilical, may require submission of a pipeline permit application to the Regional Supervisor. However, those actions address different considerations than are addressed by this section.

System Alterations

Comment—A commenter suggested removing the proposed prohibition against altering or disconnecting the pipeline or umbilical until a repair or replacement plan is approved. The commenter also asserted that this proposed requirement would affect subsea operations and impose new reporting and review requirements on industry.

Response—BSEE does not agree that the suggested changes are necessary. BSEE reviews and approves system alterations to ensure compliance with other regulations. Without an umbilical, the operator is unable to monitor casing pressure and test USVs as required under existing § 250.520; thus, BSEE must have an operator's plans for maintaining compliance with this requirement before the operator disconnects. If the operator's proposed operation of disconnecting/removing flowline/umbilical would cause the operator to be unable to perform required testing on the subsea well, then the District Manager must be involved.

Additional Safety Equipment—Subsea Trees (§ 250.832)

Section summary—This section of the final rule was derived from existing § 250.801(i), rewritten for greater clarity and to use plain language, and modified to reflect that this section covers subsea tree installations. It requires operators to equip all tubing installations that have a wireline- or pump down-retrievable subsurface safety device with a landing nipple, flow couplings, or other protective equipment above and below the SSSV in order to provide for the setting of the SSSV. The last sentence of existing § 250.801(i), generally requiring closure of surface-controlled SSSVs in certain circumstances, is no longer needed for wells with subsea trees, because this final rule establishes more specific surface-controlled SSSV closure requirements in final §§ 250.838 and 250.839.

Regulatory text changes from the proposed rule—BSEE made only minor changes to the proposed language in order to be more consistent with final § 250.818 and existing regulations.

Comments and responses—BSEE did not receive any public comments on this section.

Specification for Underwater Safety Valves (USVs) (§ 250.833)

Section summary—Final § 250.833 derives in part from existing § 250.802(c), rewritten for greater clarity and use of plain language, with references to SSVs in the existing regulation deleted in order to differentiate the requirements for the use of dry trees and subsea trees. The portions of the existing rule concerning SSVs for dry trees are codified in final § 250.819. This section now requires all USVs, and their actuators, to conform to the requirements specified in §§ 250.801 through 250.803. Final § 250.833 also clarifies the designations of the primary USV (USV1) and the secondary USV (USV2), and clarifies that an alternate isolation valve (AIV) may qualify as a USV. Final § 250.833(a) requires that operators install at least one USV on a subsea tree and designate it as the primary USV, and that the operator inform BSEE if the primary USV designation changes. Final § 250.833(a) also provides that the primary USV must be located upstream of the choke valve.

Regulatory text changes from the proposed rule—BSEE updated the proposed section to include references to API Spec. 6A and API Spec. 6AV1. In final paragraph (b), ''BSEE'' was removed before ''District Office'' for consistency and because it was unnecessary.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Alternate Isolation Valves

Comment—A commenter recommended that BSEE define the term ''Alternate Isolation Valve (AIV),'' as it is not a term generally used in the industry or defined in any of the relevant standards, such as API Spec. 6A or API Spec. 17D. The commenter stated that the BSEE regulations need to fully define the term in the regulations so that it is clear which valves the operator must describe.

Response—An AIV is any valve, in addition to the primary and secondary USVs, that acts as the USV. There are multiple names for an AIV, including ''flowline isolation valve.'' This term was used to emphasize that any valve in the subsea system that may act as a USV must meet the same requirements as the primary and secondary USV. BSEE did not make any significant changes to the proposed regulation with respect to this issue so as not to artificially limit the scope of the term ''flowline isolation valve.''

Redundant USVs

Comment—A commenter recommended revising the language of this proposed section to reflect that there are cases in which redundant USVs are installed. The commenter recommended revising the proposed language to require operators installing redundant USVs to designate one USV on a subsea tree as the primary USV and to install that valve upstream of the choke valve.

Response—No changes are necessary. This provision in the proposed rule, as carried forward into the final rule, already addressed the situation in the manner described by the commenter. Final § 250.833(b) addresses the requirements for redundant USVs.

Use of USVs (§ 250.834)

Section summary—Final § 250.834, establishing basic requirements for the inspection, installation, maintenance, and testing of USVs, is derived from existing § 250.802(d). BSEE revised the existing provision to provide greater clarity, to use more plain language, and to remove references to SSVs in order to separate the requirements applicable to dry trees from those applicable to subsea trees. This final section also adds language to expressly include USVs designated as primary or secondary as well as any AIV that acts as a USV, and to clarify that all USVs must be installed, maintained, inspected, repaired, and tested in accordance with applicable DWOPs.

Regulatory text changes from the proposed rule—This section was revised to clarify that these requirements apply to any valve designated as the primary USV and to include a cross-reference to final § 250.880 for additional USV testing requirements. The reference to § 250.880 was added based on comments received and to clarify that USV testing requirements are also found in final § 250.880.

Comments and responses—BSEE received public comments on this section and responds as follows:

Primary and Secondary USVs

Comment—A commenter recommended that the new regulation be consistent with the intent of the existing NTL No. 2009–G36, which requires only the primary USV (USV1) to pass the leak test criteria, given that secondary valves are not required by the regulations. The commenter asserted that testing secondary USVs to the same standard as the primary USV should not be required until a secondary USV becomes a primary USV. The commenter also recommended that BSEE include a reference to § 250.880 in § 250.834, as the proposed regulatory language did not directly refer to the testing requirements specified for USVs described in § 250.880.

Response—BSEE agrees with the commenter and has revised final § 250.834 to require the operator to install, maintain, inspect, repair, and test only the valve designated as the primary USV in accordance with this subpart, the applicable DWOP, and API RP 14H. BSEE also agrees with the commenter with respect to the reference to § 250.880 and has added that reference in the final section.

Specification for All Boarding Shutdown Valves (BSDVs) Associated With Subsea Systems (§ 250.835)

Section summary—Final § 250.835 is a new section that establishes minimum design and other requirements for BSDVs and their actuators. This section sets out the requirements for use of a BSDV, which for subsea systems assumes the role of the SSV required for a traditional dry tree. The BSDV is intended to ensure the maximum level of safety for the production facility and the people aboard the facility. Because the BSDV is the most critical component of the subsea system, it is necessary to subject this valve to rigorous design and testing criteria.

Regulatory text changes from the proposed rule—BSEE revised this section in the final rule by replacing the initial reference to ''BSDVs'' with the phrase ''new BSDVs and any BSDVs removed from service for remanufacturing or repair.'' This was added to address the applicability of the new requirements for BSDVs by clarifying that the provision is only applicable to new BSDVs and those removed from service for remanufacturing or repair.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

BSDV Location

Comment—A commenter requested clarification on the BSDV location requirement for floating facilities. Another commenter recommended using the current draft language from API 14C for BSDV location and allowing engineering discretion in determining the appropriate location with respect to FPSs. The commenter stated that the prescriptive language of the proposed rule would limit flexibility in the DWOP process and proposed alternate language regarding the BSDV's location.

Response—No changes are necessary. The location of the BSDV was specified in the proposed rule, and is included in the final rule, to ensure the safety of the facility. Under § 250.835(c), when the pipeline riser boards the facility, it must be equipped with a BSDV installed within 10 feet of the first point of access to that riser. Because the BSDV is crucial to the facility's safety, the final regulations (§§ 250.836 and 250.880) seek to ensure its reliability by requiring more stringent testing (*i.e.,* zero allowable leak-rate) than other valves. Similarly, because of the critical role of the BSDV, it is the first valve that must close in order to isolate production from the facility during an abnormal event or emergency. This provision decreases the possible exposure of the pipeline upstream of the BSDV to dropped objects, fire and other hazards. The shutdown valve needs to be as close as possible to where the pipeline riser boards the facility, so that the source of flow is shut-in before the area of damage, if there an emergency on the facility. The DWOP process is designed to allow for some flexibility in design, but the operator must comply with the regulations by demonstrating that its DWOP provides the same level of safety and environmental protection as provided by the regulations.

Use of BSDVs (§ 250.836)

Section summary—Final § 250.836 establishes a new requirement that operators must install, inspect, maintain, repair and test all new BSDVs and BSDVs removed for repair or remanufacture according to the provisions of API RP 14H. This section also specifies what the operator must do if a BSDV does not operate properly or if fluid flow is observed during the leakage test.

Regulatory text changes from the proposed rule—BSEE revised this section of the final rule for clarity and to align more closely with § 250.820. Final § 250.836 also clarifies that it is applicable to new BSDVs and to any BSDV removed from service for remanufacturing or repair. BSEE also added language in this section to clarify that operators must install and repair (as well as inspect, maintain, and test) BSDVs in accordance with API RP 14H, as incorporated in this section. This is also consistent with similar language used in final §§ 250.820 and 250.834 for SSVs and USVs, respectively. BSEE also updated the section to refer expressly to the testing requirements of § 250.880 and to state that if there is any gas fluid and/or liquid fluid flow observed during testing, operators must shut-in all sources to the BSDV and immediately repair or replace the valve. BSEE made these changes for consistency and clarity to ensure operators take proper actions in the specific situation.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Repair or Replacement of Leaking BSDVs

Comment—Commenters stated that the proposed requirement to repair or replace a leaking BSDV before resuming production is not consistent with the requirement to immediately repair or replace the valve, as stated in proposed § 250.880(c)(4)(iii). Also, given the potential safety implications associated with a leaking BSDV, commenters recommended that a leaking BSDV should be required to be repaired or replaced before resuming production on any manned facility. The commenters recommended that the language be consistent with proposed § 250.880(c)(4)(iii).

Response—BSEE agrees with the comment that this provision should be consistent with § 250.880(c)(4)(iii) and has revised the final rule to require that the operator immediately repair or replace a BSDV if it does not operate properly.

Emergency Action and Safety System Shutdown—Subsea Trees (§ 250.837)

Section summary—Final § 250.837, regarding emergency actions and safety system shutdowns for subsea tree installations, replaces existing § 250.801(j). It also addresses the use of a MODU or other type of workover vessel in an area with producing subsea wells. In addition, this section of the final rule adds new requirements to clarify allowances for valve closing sequences for subsea installations and specifies actions required for certain situations. Final §§ 250.837(c) and (d) describe a number of emergency situations requiring the operator to shut-in and to close the safety valves and, in certain situations, to bleed the hydraulic systems.

Regulatory text changes from the proposed rule—Throughout this section, ''BSEE'' was removed from before ''District Manager'' for consistency and because it was superfluous. The final rule also incorporates several minor, non-substantive formatting and clarifying edits. BSEE revised paragraph (b)(2) to clarify that real-time communication must be established between the MODU or other type of workover vessel and the production facility control room. BSEE also replaced ''MODU'' with ''MODU or other type of workover vessel'' throughout paragraph (b). In addition, BSEE clarified that the driller or other authorized rig personnel must secure the well using the ESD station located near the driller's console. BSEE removed the phrase ''on the host platform'' from paragraph (c)(3) because it was superfluous in the context it was used. In addition, BSEE revised final paragraph (c)(5) by adding a reference to ''other workover vessel'' for consistency with paragraph (b)(2).

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Emergency Planning

Comment—A commenter stated that no amount of detail in the regulations will address all concerns, and that rules cannot be revised or updated in a timely manner. The commenter suggested that BSEE hold operators accountable for emergency planning consistent with their management systems and the types of facilities they operate.

Response—BSEE agrees that no amount of detail in the regulations will cover all concerns; however, that does not negate our obligation to continuously improve the regulations in order to protect personnel safety and the environment. BSEE included this provision to provide direction and clarity for operators with regard to certain reoccurring events. BSEE's existing regulations contain other provisions for emergency planning, including a requirement that operators address emergency response and control in their SEMS plans under subpart S of this part (*see* § 250.1918 for more information). These complementary provisions will work together to advance safety and environmental protection in OCS operations.

Geographic Impact of Storms

Comment—A commenter suggested that the process for establishing the geographic impact of an emergency requiring shut-in for oil and compression gas wells is unclear.

Response—The geographic impact of any given emergency will be highly dependent on the fact-specific nature of that emergency. As used in this section, tropical storms are just one example of an emergency; there may be other types of emergencies that require shut-in. In the event of a specific (*e.g.,* a named) storm, any required shut-ins will be determined by the applicable storm path. This final rule will require the operator to shut-in all subsea wells in that path, not just oil and gas compression wells. If an operator has any questions or concerns about whether or when to shut-in, the operator may contact the appropriate District Manager for guidance.

Impending Named Tropical Storm or Hurricane

Comment—Several commenters suggested that the term ''impending named tropical storm or hurricane'' needs to be better defined because some named storms would not necessarily require shutting in. Commenters stated that, if the term is meant only as an example of an emergency and is not meant to be all-inclusive, then the language and title of the proposed rule should be clarified or changed. The comment suggested regulatory language providing that BSEE would not need to require operators to shut-in some subsea wells (such as wells with a subsurface safety device) during a storm.

Response—BSEE does not agree with the commenters' suggestions. Changing the title would potentially confuse the scope of this regulation since tropical storms and hurricanes are only examples of emergencies that could require shut-ins; other, non-storm emergencies could also require shut-ins. If an operator has any questions or concerns about whether or when to shut-in as a result of a specific storm or other emergency, the operator may contact the appropriate District Manager for guidance. BSEE also disagrees with the suggestion that wells with subsurface safety devices need not be shut-in during a storm when other wells are shut-in. In fact, all producing wells have subsurface safety devices of some kind, so the commenter's suggestion could result in no wells being shut-in during a storm. This would be contrary to longstanding and accepted safety practices.

Responsibilities for Wells

Comment—A commenter stated that the proposed language presupposes that the company under whose direction a MODU or workover vessel is operating is the operator responsible for any wells that may be subject to suspension of production. The commenter asserted that such responsibility should only be placed with the lease operator, notwithstanding the proposed rule's apparent assignment of responsibility with the MODU operator. The commenter suggested that BSEE revise the proposed wording in order to place the burden on the operator of producing subsea wells to take action when a MODU or other type of workover vessel is in the area.

Response—BSEE does not agree that the suggested changes are needed. This regulation is primarily directed at the lease operator. However, under § 250.146(c), those persons actually performing an activity subject to part 250 are jointly and severally responsible for compliance with those requirements; this includes the lessee, the operator, and the person actually performing the activity. This would include a MODU operator if that MODU operator is performing activities subject to regulation under part 250. Thus, it is important that the relevant parties coordinate their activities, as well as their communication and control procedures, to ensure compliance with the applicable regulatory requirements.

Drilling

Comment—A commenter asserted that the term ''driller'' as used in the proposed language is ambiguous and requires further clarification. The commenter stated that ''driller'' is not defined in the BSEE's regulations, is overly prescriptive, and is subject to multiple interpretations, including either the drilling contractor or the person serving in the position known as the ''driller'' on the MODU. The commenter suggested that the wording could also be interpreted as precluding an ''assistant driller,'' ''toolpusher,'' or others, from taking action to initiate the needed shutdown.

Response—BSEE agrees with the commenter and has revised this section of the final rule to add ''(or other authorized rig floor personnel)'' after ''driller.''

ESD Location

Comment—A commenter suggested that, for consistency with existing §§ 250.406(a), 250.503, and 250.603, the reference to ''ESD on the well control panel located on the rig floor'' be changed to ''ESD station near the driller's console or well-servicing unit or operator's work station.'' The commenter noted the importance of communicating with others in order to shut-in other potentially affected wells, and stated that such information should be identified in the plan submitted to BSEE for approval in advance of operations. The commenter also noted that the proposed wording presupposes that only a single facility's wells could be affected and seemingly fails to place an obligation on that facility's operator (or the operator of any potentially affected wells on other facilities) to shut-in the wells under their control upon receiving notification from the MODU or workover vessel.

Response—BSEE agrees with the commenter's suggestion regarding placement of the ESD station and has changed the text in final § 250.837(b)(2) to refer to the ESD station near the driller's console. For securing the other wells on the platform, the operator needs to establish direct, real-time communication between the MODU or other workover vessel and the production facility. According to § 250.837(b)(2), operators must immediately secure the well directly under the MODU using the ESD station near the driller's console while simultaneously communicating with the platform to shut-in all affected wells.

MODU or Vessel

Comment—A commenter recommended that wherever the term ''MODU'' appears in proposed § 250.837, it should be replaced by the term ''MODU or vessel.'' The commenter also stated that it is not clear that the requirement to shut-in all wells could be triggered by a dropped object in the event that communication is lost between the MODU or vessel and the platform for twenty minutes or longer. The commenter asserted that the shut-in needs to be implemented from the platform, and suggested that the shut-in requirement does not need to be applied to a well that is under the direct control of the MODU/vessel itself. The commenter also indicated that the requirement to shut-in should be reversed as soon as reliable communication is re-established between the MODU/vessel and the platform.

Response—BSEE agrees with the commenter's suggestion for changing the references to ''MODU,'' and has replaced that term throughout this section with ''MODU or other type of workover vessel,'' as used in the introductory sentence in proposed paragraph (b). BSEE also agrees that the shut-in needs to be implemented from the facility; however, that fact does not support the commenter's suggestion that the shut-in requirements should not apply to a well under direct control of a MODU. (In fact, such a well should be shut-in already, since the MODU would be there to work on the well.) As stated in paragraph (b)(2), all wells that could be affected by the dropped object—whether under control of a MODU or other workover vessel or of a platform—must be shut-in to prevent a spill.

With regard to the comment regarding reversal of a shut-in, BSEE agrees that a shut-in can be reversed once communication is restored and the District Manager approves resumption of operations.

What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system? (§ 250.838)

Section summary—Section 250.838 in the final rule establishes maximum allowable valve closure times and hydraulic system bleeding requirements for electro-hydraulic control systems. Final paragraph (b) applies to electro-hydraulic control systems when an operator has not lost communication with its rig or platform. Final paragraph (c) applies to electro-hydraulic control systems when an operator loses communication with its rig or platform. Each paragraph includes a table containing valve closure times and hydraulic system bleeding times for BSDVs, USVs, and surface-controlled SSSVs under various scenarios. BSEE derived the tables from Appendices to NTL No. 2009–G36. (Since this final rule codifies the provisions from NTL No. 2009–G36, BSEE plans to rescind the NTL and remove it from the BSEE Web page after the effective date of the final rule.)

Regulatory text changes from the proposed rule—Paragraphs (b) and (d) were updated to reflect comments received, as discussed later, and to be consistent with the language of NTL No. 2009 G–36. In addition, throughout the section, ''BSEE'' was removed before ''District Manager'' and ''District Office'' for consistency and because it was superfluous.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

MODU or Vessel

Comment—A commenter recommended that the word ''rig'' and the term ''MODU'' be replaced by ''MODU/offshore support vessel'' throughout this section.

Response—BSEE generally agrees with this comment and has replaced the terms ''rig'' and ''MODU'' with ''MODU or other type of workover vessel'' throughout this section of the final rule. This revision is also consistent with the terminology in final § 250.839.

Closure and Bleed Requirements When Communication is Maintained

Comment—A commenter asserted that proposed paragraph (b) was confusing in that it would require an operator that has not lost communication with its rig or platform to comply with the maximum allowable valve closure and hydraulic system bleed requirements listed in that paragraph's table. The commenter recommended revising the language to require compliance with the valve closure times and hydraulic bleed requirements listed in either the table or in an operator's approved DWOP, as long as communication is maintained.

Response—BSEE agrees with the commenter's suggested language, which is consistent with BSEE's original intent. Accordingly, BSEE has revised paragraph (b) in the final rule to require that the operator must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the table or the operator's approved DWOP, as long as communication is maintained.

Valve Closure Timing

Comment—A commenter suggested revising the language in proposed § 250.838(b)(2) (Pipeline pressure safety high and low (PSHL)) to provide the same requirements for bleeding both high pressure (HP) and low pressure (LP) hydraulic systems. The commenter also suggested adding language to proposed § 250.838(b)(4) in order to prevent a surface-controlled SSV from closing on a flowing well, since the HP system will vent faster than the LP system.

Another commenter suggested revising the language in proposed § 250.838(d)(2)—(Pipeline PSHL) to require a shut-down time that is determined by hydraulic analysis and confirmed during commissioning instead of using the times specified in that paragraph. The commenter asserted that it is difficult to close valves in 5 minutes on most deepwater, long step-out systems.

In addition, the commenter suggested revising the proposed requirement in § 250.838(d)(5) (Dropped Object—subsea ESD (MODU)) to ''initiate unrestricted bleed immediately'' upon communication loss for both LP and HP systems because that action would almost always result in the surface-controlled SSV closing on a flowing well. Specifically, the commenter requested that BSEE add language to this paragraph specifying that the LP hydraulic system must be vented and valves closed before the HP system is vented.

A commenter asserted that the table of valve closure and hydraulic bleeding requirements in proposed paragraph (b) should be consistent with the table in NTL No. 2009–G36, which explains what to do in case an operator cannot meet valve closure times when it has a loss of communications. The commenter stated that the table in § 250.838(d) requires immediate closure of tree valves upon Subsea ESD (MODU), and asserted that some control systems cannot meet that timing requirement, especially with regard to the LP system.

Response—BSEE agrees with the suggestion to revise the table to be consistent with NTL No. 2009 G–36 and has included those revisions in the final rule. BSEE disagrees, however, with the other changes to the tables in paragraphs (b) and (d) recommended by the commenters. The closure times in those tables are based on the best practices that are established at this time. These are reasonable, but conservative, limits that conform to the concept of having redundant and verified (*i.e.,* tested) mechanical barriers in place in the event of an emergency or abnormal condition requiring isolation of hydrocarbon flow. If communication between the operator and the production facility, or the MODU or other type of workover vessel, is lost, the system must then operate the same as a direct hydraulic system. If the system cannot meet the shut-in timing requirements in the table when communication is lost, then the operator needs to shut-in the facility. For a host facility that is a significant distance from the subsea wells, it may take an unacceptable amount of time to bleed the hydraulic lines should an event occur requiring that the hydraulic system be bled. Because the operator needs to be able to shut-in the facility as soon as possible during that type of event, the system must be able to comply with the timing requirements of the regulation. Thus, BSEE does not agree that the closure times in the tables should be replaced with a requirement that closure times be determined by hydraulic analysis and confirmed during commissioning for specific facilities. However, specific subsea valve closure timing and hydraulic bleed capability for individual facilities may be submitted for review and potential approval by BSEE in a DWOP.

What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system? (§ 250.839)

Section summary—Final § 250.839 establishes maximum allowable valve closure times and hydraulic system bleeding requirements for direct-hydraulic control systems. It contains a table of valve closure/hydraulic bleed timing requirements comparable to those in final § 250.838(b).

Regulatory text changes from the proposed rule—Throughout this section, ''BSEE'' was removed before ''District Manager'' for consistency and because it was superfluous. Paragraph (b) was updated to reflect comments received and to be consistent with the language of NTL No. 2009 G–36 and final § 250.838.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

MODU or Vessel

Comment—A commenter recommended that the term ''MODU'' be replaced by ''MODU/offshore support vessel'' throughout this section.

Response—BSEE agrees and has changed the term ''MODU'' to ''MODU or other type of workover vessel'' in final paragraph (b)(5). This revision is also consistent with the terminology in final §§ 250.837 and 250.838.

Design, Installation, and Maintenance—General (§ 250.840)

Section summary—The final rule includes the requirements previously found in existing § 250.802(a). It establishes basic requirements for the design, installation, and maintenance of all production facilities and equipment. BSEE revised the existing language to improve clarity and to use plain language and added several new production components (*e.g.,* pumps, heat exchangers) to this section that were not included in existing § 250.802(a).

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this proposed section in the final rule.

Comments and responses—BSEE did not receive any comments on this section.

Platforms (§ 250.841)

Section summary—The section includes the requirements previously found in existing § 250.802(b). BSEE also added new requirements for facility process piping in final § 250.841(b). The new paragraph requires adherence to existing industry standards (*i.e.,* API RP 14E and API 570), which are incorporated by reference in final § 250.198. The final rule also specifies that the District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section in the final rule.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Crewing for Arctic Facilities

Comment—A commenter stated that the OCS Platform requirements in the proposed section did not specify any manning requirements and asserted that the regulations should include specific manning requirements for Arctic OCS facilities and should prohibit unmanned facilities.

Response—Appropriate crewing is a facility—and operation-specific issue. As previously stated in part IV.B.3, BSEE understands that the Arctic OCS presents unique operating conditions and other challenges. BSEE recently addressed exploratory drilling requirements for the Arctic OCS in a final rule published on July 15, 2016 (81 FR 46477), and BSEE may address other Arctic-specific issues in future rulemakings, guidance documents, or on a case-by-case basis.

Piping Repairs

Comment—A commenter asserted that limiting the duration of temporary piping repairs to 30 days could be problematic since a significant fabrication or construction backlog could hinder final repairs. The commenter also stated that weather and logistics will play a key role when the permanent repair is actually being conducted; thus, it may take more than 30 days to complete the permanent repair. The commenter suggested adding language to this provision to allow the District Manager to approve extensions to the duration of a temporary repair in 30-day increments. Another commenter requested clarification on whether the 30-day limit on approvals of the duration of temporary repairs to facility piping is only for piping in hydrocarbon service or for all facility piping.

Response—BSEE does not agree that the suggested changes are appropriate. BSEE considers pressures, type of systems, and other factors in considering requests for approval of temporary repairs to piping. The longer the temporary repair is in place, the greater the risk that the repair will fail, given that the temporary repair material is generally not designed for long-term use in accordance with industry standards for permanent piping (*e.g.,* API RP 14E, API 570). Moreover, the temporary repair materials are often not fire-rated, which also increases risks. Based on BSEE's experience, 30 days is typically enough time to make permanent repairs. If there are concerns about the length of the 30-day period for temporary repairs, the operator should contact the appropriate District Manager. The time limit on approval of temporary repairs applies to all facility piping, not just piping in hydrocarbon service.

Platform Definition

Comment—A commenter stated that although this proposed section would require compliance with specific standards for OCS platforms, the term ''platform'' is not defined in the regulations. The commenter requested that a definition of ''platform'' be added to the final regulations. The commenter added that, in the Arctic, OCS facilities are currently built on gravel islands and may be installed on bottom-founded offshore structures in the future. The commenter suggested that the final regulations should clarify whether § 250.841 will apply to Arctic OCS operations conducted on gravel islands or bottom-founded offshore structures, or whether an additional Arctic-specific section will be added to address these facility types.

Response—As previously explained, BSEE understands that the Arctic presents some unique situations, and BSEE may address Arctic-specific issues in future rulemakings, guidance documents, or on a case-by-case basis. In the meantime, adding a definition of ''platform,'' particularly one addressing Arctic-specific circumstances, is beyond the scope of this rulemaking. However, when BSEE reviews a permit, it considers the specific operating and environmental conditions. Gravel islands are different from platforms in several ways, and may need to meet different requirements or permit conditions. If there are any questions concerning the applicability of this final rule to gravel islands, the operator should contact the appropriate District Manager for evaluation on a case-by-case basis. (For activities on the Arctic OCS, any reference in this part to District Manager means the BSEE Regional Supervisor for the Alaska region.)

API 570

Comment—One commenter stated that this section should not refer to API 570 because that standard was developed for downstream operations, not offshore oil and gas upstream operations. Thus, the commenter asserted that there would be many potential conflicts if that document were applied to offshore operations as proposed. The commenter recommended that, before the document is incorporated in its entirety, BSEE review the document and determine what sections are applicable to offshore production operations.

Response—BSEE disagrees with the comment. API 570 is the industry standard for piping. Although API 570 was developed primarily for the petroleum refining and chemical process industries, it states that it may be used for any piping system. Moreover, the commenter did not assert any specific conflicts related to using API 570 for offshore production operations. In fact, this document is extensively cited and widely used by the offshore oil and gas industry, especially with respect to inspection of piping (*e.g.,* inspection methods, inspection frequency, non-destructive testing, and corrosion rates for determining the life expectancy of the piping). These issues are as applicable to offshore operations as they are to onshore operations, and are critical for ensuring the mechanical integrity of the piping. If any operator believes there is a specific conflict between API 570 and that operator's offshore operations, the operator should contact the appropriate District Manager for guidance.

Comment—A commenter suggested adding language to proposed § 250.841(b) to clarify that API 570 applies downstream of the boarding valve for design requirements and to clarify the types of facility piping to which the provisions regarding temporary repairs will apply.

Response—BSEE does not agree that the suggested additions are necessary. The proposed and final regulatory text for § 250.841(b) refers to ''production process piping.'' Subpart H applies to any piping confined to a production platform that is downstream of the BSDV. Piping upstream of the BSDV is covered by the pipeline regulations, under subpart J. In addition, as previously stated, the provisions regarding temporary repairs apply to all facility piping.

Jurisdiction

Comment—A commenter asserted that BSEE should limit the requirements under paragraph (b), as applied to floating facilities, to equipment/systems and piping over which BSEE has jurisdiction.

Response—BSEE does not need to revise paragraph (b) as suggested. These regulations apply only to operations that are under BSEE authority. This regulation ensures that operations with respect to platform production facilities and platform production process piping are conducted in a manner that prevents or minimizes the likelihood of fires (*e.g.,* from leaking pipes carrying produced hydrocarbons) and other occurrences that may cause damage to property or the environment, or endanger life or health. Thus, BSEE's regulation of these operations is within the scope of its legal authority to regulate platforms erected on the OCS and engaged in the production of oil or gas.

Approval of Safety Systems Design and Installation Features (§ 250.842)

Section summary—Final § 250.842 recodifies the requirements of existing § 250.802(e), regarding applications for approval of production safety systems, including the service fee associated with the submittal of those applications. This section outlines the requirements of a production safety system application and requires adherence to several API standards pertaining to the design of production safety systems and related piping and electrical systems (*i.e.,* API RP 14C, API RP 14E, API RP 14F or RP 14FZ, API RP 14J, API RP 500 or RP 505).

The final rule also requires completion of a hazards analysis during the production safety system design process and requires a hazards analysis program to assess potential hazards during the operation of the platform. The final rule also requires that the designs for mechanical and electrical systems be reviewed, approved, and stamped by a registered professional engineer (PE). It also requires that a registered PE certify the as-built piping and instrumentation diagrams (P&IDs). This section also specifies that the PE must be registered in a State or Territory of the U. S. and have sufficient expertise and experience to perform the applicable functions.

Final § 250.842 requires that operators certify that all listed diagrams (including P&IDs) are correct and accessible to BSEE upon request, and that the required as-built diagrams outlined are submitted to the District Manager within 60 days after production commences.

In addition, final § 250.842(b)(3) includes a reference to the hazards analysis requirement of § 250.1911 and, as discussed in the proposed rule, imposes a requirement that the operator certify that it performed a hazard analysis during the design process in accordance with API RP 14J and that a hazards analysis program is in place to assess potential hazards during the operation of the platform.

Regulatory text changes from the proposed rule—Throughout this section, BSEE removed the word ''BSEE'' from before ''District Manager.'' In addition, based on consideration of public comments, BSEE revised paragraphs (b)(2) and (d) to add ''an appropriate'' before ''registered professional engineer.'' Paragraph (b)(3) was substantially revised to, among other things, clarify that the required hazards analysis must be performed in accordance with the existing SEMS hazards analysis requirement and with APR RP 14J. Paragraph (d) was revised to clarify that a registered PE must certify the as-built diagrams, outlined in paragraphs (a)(1) and (2), for the new or modified production safety system.

BSEE also made several minor, non-substantive edits to improve clarity and to use plain language.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

BSEE Jurisdiction

Comment—A commenter raised questions about BSEE and USCG jurisdictional areas of responsibility over electrical systems.

Response—The comment was unclear. The requirements of § 250.842 address what information must be included in a production system safety application. These regulations apply only to operations and systems that are under the authority granted to the Department by OCSLA. More detailed discussion of BSEE's and USCG's jurisdiction is found in part IV.B.2 of this document.

Professional Engineers

Comment—One commenter suggested that the final rule should specifically require a U.S.-registered professional mechanical engineer to stamp all mechanical system designs, and require a U.S.-registered professional electrical engineer to stamp all electrical system designs.

Two commenters, however, suggested revising proposed § 250.842(b)(2) to allow chartered engineers or other non-U.S. engineers to design, review and approve mechanical and electrical systems because a large number of floating structures are engineered and built outside the U.S. The commenter asserted that the proposed wording could introduce significant legal issues when applied to modifications on existing facilities. The commenters recommended that BSEE revise paragraph (b)(2) to address these issues. Another commenter supported the proposed requirement that PEs be registered by a State or Territory, but requested that BSEE expressly state that the term ''sufficient expertise and experience'' for PEs includes experience with Arctic and harsh environments for systems used in the Arctic region.

Response—With regard to the first commenter's suggestions, BSEE agrees that proposed § 250.842(d) was potentially overbroad. Therefore, in the final rule, we have revised § 250.842 by inserting the words ''an appropriate'' before ''registered professional engineer'' to clarify BSEE's intention that the registered professional engineer be qualified in the particular discipline relevant to the certification, (*e.g.,* an electrical engineer to certify electrical system designs or a mechanical engineer to certify mechanical system designs).

With regard to the suggestions to allow non-U.S. registered engineers to perform tasks under paragraph (b)(2), no changes are necessary based on these comments. A reliable verification, with stamping, by a registered PE of the designs for the mechanical and electrical systems is important to BSEE's decisions regarding the suitability of a proposed production safety system, and BSEE has no way of verifying a registered PE stamp from a foreign country.

With respect to the commenter's assertions about existing facilities, this regulation is tailored to improve production process safety without unreasonably burdening the industry. In addition, although the commenter indicated that the proposed rule could create significant legal issues when applied to existing facilities, the commenter failed to specify what those legal issues might be, and it is not clear why application of this regulation to existing facilities would raise any significant legal issues. The relevant portion of proposed § 250.842(b)(2), to which this comment was directed, requires that the production safety system application include a certification that the mechanical and electrical systems designs were reviewed, approved, and stamped by an ''appropriate'' registered PE. Given the importance of the certifications required by final § 250.842(b), BSEE did not make any significant changes to this proposed regulation based on this commenter's suggestions.

BSEE did not revise paragraph (b)(2) to add language regarding experience with Arctic environments. BSEE intends that the requirement that an appropriate PE have ''sufficient expertise and experience'' will include experience with conditions where the operations will take place, including the Arctic environment for Arctic operations. As discussed earlier, BSEE may address specific Arctic-related issues in separate rulemakings, guidance or documents in the future.

Shut-in Tubing Pressure Changes

Comment—A commenter asserted that the requirement in proposed paragraph (a)(1), to include a schematic piping and instrumentation diagram in the operator's production safety system application, would add unwarranted burdens to keep such diagrams updated. To reduce the asserted burden, the commenter recommended deleting proposed paragraphs (a)(1)(i) and (a)(1)(iii) regarding well shut-in tubing pressure and pressure safety valve (PSV) set points, respectively. The commenter stated that shut-in tubing pressure and PSV set points change often, and thus would require resubmitting updated drawings to BSEE frequently. The commenter suggested that this reporting burden would not provide additional value.

Response—BSEE does not agree that the suggested change is necessary. BSEE does not expect operators to submit drawings every time the shut-in tubing pressures or PSV set points change, unless the production safety system changes as a result (*e.g.,* by installation or removal of equipment or safety devices). Operators will need to submit drawings to BSEE whenever they plan to modify the production process safety system, to make sure the system is acceptable and complies with the regulations. If an operator has any question as to whether a specific change would require resubmission of a process safety system application, the operator should contact the District Manager. As BSEE gains experience implementing this regulation, BSEE may provide additional guidance on when process safety system applications must be updated or resubmitted.

Piping Specification Breaks

Comment—One commenter noted that proposed § 250.842(a)(1)(ii) would have required that piping specification breaks be included on a schematic piping and instrumentation diagram, whereas BSEE District Engineers currently accept system pressure specification breaks, as opposed to individual ''piping'' specification breaks, for Safety Analysis Flow Diagrams (SAFDs). A commenter provided an example involving the compressor skid. According to the commenter, using piping specification breaks would yield a wide variety of breaks (*e.g.,* from inlet scrubbers to compressor suction and discharge bottles), while using system specification breaks would minimize the number of specification breaks that must be included in the diagram under paragraph (a)(1). The commenter implied that this would eliminate numerous unimportant details from the diagram and would simplify normalized operating systems, for a more robust analytical result.

Response—BSEE does not agree with the commenter's suggested change. The piping specification breaks provide BSEE with important information for its review of the schematics and diagrams to ensure that the safety system has been properly designed to account for changes in the piping design (*e.g.,* different pipe sizes resulting in pressure changes). The P&ID is a more detailed drawing than the SAFD. BSEE needs the individual pipe specification breaks to thoroughly analyze the system.

Safety Analysis Flow Diagrams

Comment—One commenter noted that, under proposed § 250.842(a)(1)(ii) and (a)(2), the Appendix E requirements of API RP 14C for the SAFD reflect the need for maximum pressures to be shown for pressure vessels, pipelines and heat exchangers. The commenter questioned whether, since this new requirement applies to piping and instrumentation diagrams, combining the two documents (*i.e.,* the P&ID and the SAFD) would be acceptable for submittal and approval. The commenter also asserted that all items listed in proposed § 250.842(a)(1) and (2) could be included on the combined document.

Response—BSEE does not agree with the commenter's suggestion for combining these two documents. The operator needs to submit both P&IDs and SAFDs. Industry already has standards in place for both documents and each document includes valuable information that is not found in the other. BSEE may consider a combined document in the future, as suggested, if industry establishes a standard process safety flow diagram that contains all of the information that BSEE otherwise would receive in P&IDs and SAFDs.

Maintaining Drawings

Comment—A commenter stated that he requirement in proposed paragraphs (a)(1) and (2) to maintain two sets of drawings would be burdensome and create opportunities for errors and omissions to occur. A commenter noted that the preamble of the proposed rule referred to the *Atlantis* investigation in justifying the new requirements for drawings; however, the commenter asserted that the recommendations in the *Atlantis* report did not identify a need for revisions to the drawing(s) requirements of existing subpart H and that those recommendations actually addressed issues covered in existing subpart I. The commenter recommended combining proposed paragraphs (a)(1) and (2) into a single requirement.

Response—BSEE does not agree with this suggestion. The importance of correct as-built documents and professional engineer stamps was highlighted in the *Atlantis* incident investigation report, prepared by BSEE's predecessor agency, the Bureau of Ocean Energy Management, Regulation and Enforcement in 2011.[22] The *Atlantis* report addressed the scope of the existing regulatory requirements related to engineering documents and hazard analyses, and pointed out the difficulties in identifying, organizing and tracking proper ''as-built'' drawings from other documents, such as ''issued for design'' or ''issued for construction'' drawings. At the time of the report, operators were not required to submit the engineering documents, including ''as-built'' diagrams referenced in hazard analysis documents.

Although the *Atlantis* report did not make specific recommendations for revisions to subpart H, several of the important issues identified in the report, including the need for operators to have a document management system to ensure accurate sets of drawings, are relevant to and addressed by this final rule. In particular, the issues discussed in the *Atlantis* report related to ''as-built'' P&IDs and to other diagram requirements are addressed by this section's requirements for:

- Stamping of engineering documents by a registered PE;
- Certification by the operator that all listed diagrams, including P&IDs, are correct and accessible to BSEE upon request; and
- Submittal of a certification to the District Manager, within 60 days after production begins, that the ''as-built'' diagrams, as described in final § 250.842(a)(1) and (2) are on file and have been stamped by an appropriate PE.

Potential Ignition Sources

Comment—A commenter recommended removing proposed paragraph (a)(3)(ii) from the final rule, asserting that the term ''potential ignition sources'' is ambiguous and that the value of the additional information is not apparent.

Response—BSEE disagrees. This information (*e.g.,* identification of areas where potential ignition sources are to be installed) is necessary to ensure that the operator identifies possible hazards and for BSEE to ensure that those hazards are identified, addressed, and mitigated. The final rule, as proposed, provides specific details on what the operator needs to include.

One-Line Electrical Drawings

Comment—One commenter asserted that the requirement in proposed paragraph (a)(3)(iii) for one-line electrical drawings for all electrical systems would be an expansion of existing requirements and requested that BSEE limit final paragraph (a)(3)(iii) to submittals for new facilities only.

Response—BSEE disagrees. Proposed and final § 250.842(a)(3)(iii) retains, and does not expand the scope of, the information required by existing § 250.802(e)(4)(ii), and operators are already complying with that longstanding requirement. This section of the final rule only moves the current requirements to a new section. BSEE did not propose, and has not made, any substantive revisions to the existing regulatory requirement.

Whether To Limit Requirement for Certain Schematics to New Facilities

Comment—A commenter recommended that BSEE limit the expanded requirement under proposed paragraph (a)(4) (schematics of fire and gas-detection systems) to submittals for new facilities only.

Response—BSEE disagrees with the requested limitation. This information is already required by existing § 250.802(e)(6), and this final rule simply moves that longstanding requirement to a new section, with no substantive changes. Operators are already complying with the existing requirement and BSEE sees no need or justification for limiting its scope to new facilities.

Definition of ''Designs''

Comment—One commenter noted that proposed paragraph (b) would require ''designs for the mechanical and electrical systems . . . [to be] reviewed, approved, and stamped by a registered professional engineer(s).'' The commenter asserted that a vital component of the process safety system is the implementation of appropriate safety and control programming logic in either pneumatic panels or programmable logic controller (PLC) processors, much of which is carried out by equipment suppliers and/or programmers not directly supervised by registered engineers. The commenter recommended adding a definition for ''designs'' in the final rule.

Response—BSEE disagrees with that recommendation. Adding a definition of ''designs'' in this section is not necessary and would not substantially clarify the content of the regulation. The terms used in paragraph (b), including ''designs,'' are well-established and commonly used in the affected industry, and have long been used in the existing regulations in the same context as they are used in this rulemaking.

[22] *See* ''BP's *Atlantis* Oil and Gas Production Platform: An Investigation of Allegations That Operations Personnel Did Not Have Access to Engineer-Approved Drawings'' (March 4, 2011). A copy of this report is available online at: *https://www.bsee.gov/sites/bsee.gov/files/panel-investigation/incident-and-investigations/03-03-11-boemre-atlantis-report-final.pdf.*

Electronic PE Reviews

Comment—A commenter recommended rewording paragraph (b)(2) to allow for an electronic review by a PE in lieu of requiring that hard copies be stamped. The commenter asserted that the proposed wording of paragraph (b)(2) could also create significant ambiguity when applied to modifications on existing facilities. The commenter suggested that stamping and/or certification be limited to new systems/designs that are ''to be installed.''

Response—No changes are necessary. Electronic stamps of a registered PE are acceptable under this section, as long as they provide the same authentic verifiable information as a PE stamp applied to paper. For example, the electronic stamp could be a jpeg of the PE stamp, depending on what each state allows its registered engineers to do. Regarding the assertion of potential ambiguity if the PE review requirement is applied to modifications of existing equipment, the commenter failed to provide any support for that assertion, and BSEE is not aware of any ambiguity that warrants changing the applicability of this requirement to modifications to existing equipment in addition to installation of new equipment.

Independent Third-Parties

Comment—A commenter proposed that BSEE change proposed paragraph (b)(2) to require that the designs for the mechanical and electrical systems be reviewed, approved, and stamped by an independent third-party. The commenter suggested that independent third-party organizations have the multi-disciplinary knowledge to fully evaluate the safety of a complete production system and can demonstrate to regulators that they have comprehensive quality and work processes and training and qualification programs for their employees.

The commenter also asserted that, as BSEE moves to incorporate risk principles into its safety regime, DNV GL's Offshore Service Specification DSS–OSS–300, Risk Based Verification, may help BSEE and industry achieve their safety objectives. The commenter noted that, in general, verification based on risk is founded on the premise that the risk of failure can be assessed in relation to an acceptable risk level and that the verification process can be used to manage that risk, thus making the verification process a tool to maintain the risk below the acceptance limit. The commenter also suggested that verification based on risk helps to minimize additional work and cost, while maximizing risk management effectiveness.

Response—No changes are necessary. Paragraphs (b)(2) and (d) require certification that an appropriate registered PE has stamped the design documents, which is intended to implement one of the recommendations in the *Atlantis* report. Having a registered PE review, approve, and stamp those documents provides BSEE with an additional review tool to ensure the documents are correct and confirmed by someone with the experience and expertise to do so. BSEE is aware that some independent third-parties may lack the same relevant experience and expertise that an appropriate registered PE possesses. For example, BSEE is aware that some engineering firms may allow engineers who are not registered PEs to perform design reviews and use the firm's stamp; therefore, BSEE does not agree at this time that use of an engineering firm to perform those tasks would provide the same level of verifiable assurance that the reviews of these critical systems have been conducted by appropriately qualified engineers. However, BSEE intends to monitor and evaluate implementation of this requirement and may consider, based on that experience, whether an alternative review process, such as use of independent third-parties, should be provided under this regulation. In the meantime, if an operator believes that an alternative review and verification process would be at least as effective as the regulatory requirement, it can request BSEE's approval of such an alternative under § 250.141 on a case-by-case basis.

As to the commenter's second suggestion, the requirements in paragraph (b)(2) represent a practical and effective means of verifying that the mechanical and electrical systems have been designed properly to perform their critical functions in a manner similar to the longstanding requirement under existing § 250.802(e)(5). Thus, BSEE does not agree with the commenter's suggestion that the approach taken by this final regulation may cost too much or fails to manage risks appropriately. BSEE also does not agree that the commenter's suggested ''risk-based'' approach would minimize costs and maximize risk management. However, BSEE is continually evaluating risk-based methods to improve safety and environmental protection, and BSEE may consider at a later date whether an alternative risk-based approach to system design verification is warranted.

Classification Societies and Certification Authorities

Comment—A commenter requested, for purposes of proposed paragraph (b)(2), that BSEE accept the review and approval by a classification society of the mechanical and electrical systems as equivalent to the review, approval and stamping of systems designs by a registered PE. The commenter based this request on BSEE's existing regulations at § 250.905(k), which provide for review, approval and certification by a ''classification society'' as an alternative to the same functions performed by a registered PE under that section. The commenter asserted that the USCG also recognizes review and approval by classification societies as equivalent to the certification by a registered professional engineer. A second commenter made similar statements and requested that BSEE revise this section to allow ''certification authorities,'' in lieu of registered PEs, to review, approve and stamp mechanical and electrical system designs. The commenter provided no examples or criteria for identifying any certification authorities.

Response—No changes are necessary. A classification society or a ''certification authority'' could be used by an operator to review and approve the relevant design documents as long as the classification society or certification authority provides a qualified, registered PE to review, approve, and stamp the documents. However, for the same reasons discussed in response to the preceding comment (regarding independent third-parties), BSEE does not have reason to believe at this time that review and approval by a classification society or certification authority, without use of an appropriate registered PE, would provide the necessary level of confidence that the mechanical and electrical systems are properly designed to perform their critical roles in the production process safety system. However, if an operator believes that an alternative review and verification process involving a classification society or certification authority would be at least as effective as the regulatory requirement for use of a registered PE, it may request BSEE's approval of such an alternate procedure on a case-by-case basis under § 250.141.

Applicability of PE Review and Approval

Comment—A commenter suggested that proposed paragraph (b)(2) should be revised to clarify whether these provisions apply to all electrical and mechanical systems or just to those related to safety systems. The commenter also suggested that the final rule should make provisions for monogrammed mechanical and electrical systems or equipment.

Response—BSEE does not agree that the suggested changes are necessary. Paragraph (b)(2), as proposed, clearly applies to all mechanical or electrical systems that are included in the operator's production safety system application for approval. Monograms are not a substitute for PE review and verification because monograms only represent that the system was in compliance with the standard at the time of manufacture; they do not provide any information about any post-manufacture changes made to the system. BSEE needs to verify, however, that the drawings are accurate for the systems and equipment that are actually installed on the facility. Thus, final paragraphs (b)(2) and (d) require certification that a registered PE stamped the actual documents.

Comment—A commenter asserted that the hazards analysis specified by proposed paragraph (b)(3) would require more detail than a similar requirement for the operator's SEMS program. The commenter suggested that BSEE clarify how paragraph (b)(3) and the SEMS hazards analysis requirements complement or differ from each other, with the ultimate goal of establishing one standard for hazards analysis.

Another commenter asserted that the placement of the hazards analysis requirement in § 250.482(b)(3) is confusing given that hazards analyses are covered by the subpart S (SEMS) regulations, API RP 75, and API RP 14J, and suggested that any alterations to hazards analysis requirements should be made through revision of subpart S or the industry standards. The commenter also asserted that the reference to ''during the design process'' in proposed paragraph (b)(3) is vague and potentially confusing with respect to whether it is referring to the original design process or to the design process of a modification. The commenter recommended removing ''the ''design process'' from the final rule. The commenter also recommended that BSEE delete paragraph (b)(3) entirely or revise paragraph (b)(3) to read: ''You must certify that a hazard analysis was performed in accordance with subpart S and API RP 14J (incorporated by reference as specified in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the platform.''

Response—BSEE agrees, in part, with these comments and has revised final paragraph (b)(3) to state that the operator must certify that its hazards analysis was performed in accordance with § 250.1911 and API RP 14J, and to clarify that the operator must have a hazards analysis program in place to assess potential hazards during the operation of the facility. BSEE also deleted the proposed requirement to perform the analysis ''during the design process.'' These revisions clarify that the hazards analysis required by this paragraph must satisfy the SEMS requirement, with respect to the relevant safety systems, as well as the more specific analysis required by API RP 14J. This will result in hazards analyses under subpart H that are consistent with the subpart S requirements, but that likely will provide more specific details regarding the relevant safety systems than subpart S alone might require.

Certification of Mechanical and Electrical Systems Installations

Comment—A commenter recommended that BSEE allow certification of mechanical and electrical systems installation through other means than a letter from the operator.

Response—No changes are necessary. Final § 250.842(d) calls for the operator to submit a letter certifying the accuracy of the as-built drawings. The letter provides documentation to assist BSEE in verifying that the drawings are consistent with the mechanical and electrical systems. Within 60 days of first production, the operator must submit updated as-built drawings along with a certification that a PE reviewed and stamped these drawings. These written documents will help BSEE ensure that the system was built according to the original plan submitted to BSEE. However, an operator may submit the certification letter electronically, if it chooses, or through BSEE's e-facility safety system permitting system.

Notification of Safety System Testing

Comment—A commenter suggested that BSEE revise proposed § 250.842(c) to clarify the type of approval or acknowledgement that the District Manager will issue following submission of the required documents. The commenter also suggested that BSEE revise proposed paragraph (c) by adding a requirement that a separate notification be submitted to the District Manager, as required by § 250.880, at least 72 hours before commencing production safety system testing.

Response—In response to the first comment, paragraph (c) only requires that the operator notify BSEE that the mechanical and electrical systems were installed in accordance with the designs previously approved by the PE; there is no BSEE approval or response required under paragraph (c).

Regarding the second comment, BSEE is not adding a reference to the production system testing notice required by § 250.880(a)(1) to § 250.842(c) as suggested. Section 250.842(c) deals with the certification required to be submitted prior to production, while the production safety system testing notification required by final § 250.880 may and generally will take place after production begins. Referring to the testing notification requirement from § 250.880 in § 250.842 is unnecessary and potentially confusing.

Certification of As-Built P&ID

Comment—A commenter asserted that certification of as-built P&ID under proposed paragraph (d) would be more appropriately done by a CVA surveyor than by a registered PE. The commenter also asserted that the proposed rule does not address the issues in the *Atlantis* report.

Response—No changes are necessary. As previously discussed, this rule addresses a number of the recommendations discussed in the *Atlantis* report (which, among other issues, evaluated complaints about the operator's access to certain engineering documents), and applies them in the context of production operations under subpart H. In particular, § 250.842(d) requires operators to provide as-built diagrams to BSEE and that operators certify that all listed diagrams, including P&IDs, are correct and accessible. The rule also addresses other issues identified in the *Atlantis* report by requiring a specific stamp by a PE on both the designs and the as-built diagrams, verifying their correctness, and by requiring the operator to certify that the equipment was installed in accordance with the approved designs. These measures provide BSEE with additional verification that the equipment on the facility was designed, built, and installed properly. Similarly, since some piping may be changed during construction, due to the actual layout, once the facility is fabricated and production begins, § 250.842(d) requires operators to submit the as-built drawings to ensure that any changes are documented.

Comment—One commenter asserted that the requirement in proposed § 250.842(d) for certification by an operator, within 60 days after production begins, that the as-built P&IDs and SAFDs have been certified correct and stamped by a registered PE would conflict with the engineering laws of many States. The commenter stated that engineers may only seal documents which they have verified as being correct and, thus, cannot legally certify as-built drawings because such certification would imply that all of the construction satisfies the applicable codes and standards. The commenter asserted that this further implies that the certifying engineer must be in charge of all of the construction quality assurance/quality control activities that verify compliance with construction codes and standards.

Response—BSEE does not agree that this comment warrants any changes and is not aware of any specific conflicts between these regulations and any State law. However, if any operator believes there is any potential conflict the operator should notify the District Manager so BSEE can review the situation and respond appropriately on a case-by-case basis. In the event an actual or potential conflict arises, the operator could also seek approval for an alternative process or a departure under §§ 250.141 and 250.142, respectively.

As-Built P&ID Timeframe and Field Verification

Comment—A commenter recommended that all references to ''piping and instrument diagrams'' be replaced with references to ''process safety flow diagrams.'' The same commenter asserted that 60 days is not sufficient to validate the drawings as correct, certify the drawings as correct, and submit the as-built diagrams and the certification to the bureau. The commenter recommended that BSEE revise paragraph (d) to require the operator to provide BSEE with a copy of the as-built P&IDs within 180 days after production begins.

Another commenter stated that it did not understand the need for the rule to state that all approvals are subject to field verification. The commenter asserted that such verification is a standard practice with any inspection and enforcement process. That commenter and another commenter recommended that BSEE revise paragraph (f) to remove the requirement for field verification of all approvals of design and installation features.

Response—No changes are necessary. P&IDs, SAFDs, and SAFE charts are required, as provided in paragraph (a), before BSEE will approve the safety system. After the platform is producing, BSEE requires the operator to submit these documents again to ensure that any minor changes made during the construction phase are captured. The 60-day timeframe in paragraph (e) for submitting the as-built diagrams to BSEE is sufficient for that purpose; since the facility is built before production begins, the operator will have more than the 60 days after production begins to make these corrections and have the drawings certified. BSEE needs these documents for inspection purposes. The original drawings are used during pre-production, while the as-built drawings are necessary for any BSEE inspection conducted after the platform is on-line and to notify the operator if there are any concerns with the as-built diagrams. The P&IDs are a critical element of this final rulemaking and industry standards (such as API RP 14C, API RP 14J, and API RP 14F) and are separate and distinct from SAFDs.

In addition, removing the sentence pertaining to field verifications from paragraph (f), as suggested by the commenters, would serve no useful purpose, since the regulation also provides that those documents must be made available to BSEE upon request and since, as with all similar documents, the P&IDs and SAFDs are subject to field verification by BSEE during the inspection process.

As-Built Diagrams

Comment—A commenter asserted that paragraphs (d) and (e) might conflict with some State requirements under which construction issued documents are sealed while as-built documents are not. The commenter also stated that State requirements also require that the ''sealing engineer'' be the responsible engineer in charge of the design phase.

Response—No changes are necessary. BSEE does not regulate how operators create the diagrams. As previously explained, BSEE needs to ensure that the diagrams are properly reviewed by qualified PEs and that they meet the standards incorporated in this section. This regulation does not require PEs to be involved in anything that they are not already authorized to do. In the event an actual or potential conflict between this rule and any applicable State law arises, however, the operator should contact the District Manager for guidance. The operator may also seek approval for an alternate process or a departure under §§ 250.141 and 250.142, respectively, on a case-by-case basis.

Paperwork Burden and As-Built Diagrams

Comment—A commenter asserted that proposed paragraph (e) of this section would create a new requirement (to submit as-built P&IDs and SAFDs to BSEE within 60 days after production commences) and that the commenter did not understand the purpose of that requirement. The commenter noted that BSEE will have the original design diagrams as part of the application process, and that BSEE will also receive a certification that the installation was done in accordance with the approved diagrams. The commenter asserted that this requirement creates an undue paperwork burden on both the company and the bureau and added that BSEE had severely underestimated the costs for maintaining the ''as-built'' drawings for the life of the facility (as required by paragraph (f)). The commenter recommended that this requirement be deleted.

Response—BSEE disagrees with these comments. As previously explained, BSEE must have up to date as-built diagrams, which accurately reflect the actual systems in place, for review and inspection purposes, including providing notification to the operator of any BSEE concerns about differences between the original approved diagrams and the as-built diagrams. Modifications are often made to systems during construction or during initial operations, potentially rendering the approved drawings that accompanied the application obsolete. If no changes are made to the system after approval, however, an operator should be able to submit the same drawings that were originally stamped by the PE at little or no extra cost. BSEE's estimates for determining the costs and burdens related to as-built diagrams were based upon BSEE's best professional judgment.

Applicability to Existing Facilities

Comment—A commenter noted that proposed paragraph (f) requires that as-built P&IDs be maintained for the life of the facility. The commenter asserted, however, that the proposed rule did not specify whether paragraph (f) applies only to facilities installed/approved after publication of the final rule or whether it also applies to existing facilities. The commenter suggested that the rule and the related information collection approval should clearly state that paragraph (f) applies only to facilities installed and approved after publication of the final rule. The commenter asserted that the costs and information collection burdens would be considerable if as-built diagrams are required for existing facilities.

Response—No changes are necessary. The requirement for as-built diagrams will apply to all production facilities installed or modified after the effective date of the final rule. All safety system submittals made after the effective date of the final rule must comply with the requirements of final paragraphs (a) through (e). All production safety system design and installation documents approved under this section will need to be maintained and readily available as required by paragraph (f).

Production System Requirements—General (§ 250.850)

Section summary—The final rule moves the contents of existing § 250.803 into a number of new sections (final §§ 250.850 through 250.872). The provisions of existing § 250.803 were rewritten and reorganized in the new sections to improve readability by making each section shorter and focused on a specific issue. In particular, the contents of existing § 250.803(a) have been moved to final § 250.850, which establishes general requirements for production safety systems, including requiring operators to comply with API RP 14C.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section. BSEE slightly revised the reference to API RP 14C to clarify that operators must also comply with the production safety system requirements of that standard.

Comments and responses—BSEE did not receive any comments on this section.

Pressure Vessels (Including Heat Exchangers) and Fired Vessels (§ 250.851)

Section summary—The contents of existing § 250.803(b)(1), establishing requirements for pressure vessels (including heat exchangers) and fired vessels, have been moved to final § 250.851. A table in paragraph (a) establishes basic requirements for production systems; paragraph (b) addresses operating pressure ranges; and paragraph (c) addresses pressure shut-in sensor settings.

Regulatory text changes from the proposed rule—The text of this section has been revised for clarity and plain language, and language has been added for completeness (*e.g.,* approval of uncoded vessels and operating pressure changes). Paragraph (a) has been revised to conform better to the MOA–OCS–04 between BSEE and the USCG, the referenced industry standards, and existing regulations, and to respond to comments received. The final rule clarifies that paragraph (a) of this section applies to pressure vessels and fired vessels that support production operations. In final paragraph (a), BSEE removed provisions from the proposed rule that related to existing pressure and fired vessels with operating pressures of less than 15 psig. In final paragraph (a)(2), BSEE provided a period of time (540 days from publication of the final rule) after which BSEE approval is required for continued use of certain uncoded pressure and fired vessels. In final paragraph (a)(3), BSEE added an exception for pressure vessels where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only.

BSEE also revised final paragraph (b), based on comments received, to clarify the requirements for the establishment of new operating pressure ranges. This includes clarifying that the operator must establish the new operating pressure range after the system pressure has stabilized, and that pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no longer than 30 days.

Paragraph (c) was revised to include clarification that initial set points for pressure shut-in sensors must be set utilizing gauge readings and engineering design.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Tank Design and Operation

Comment—One commenter asserted that the regulations should be revised to state that these sections are not applicable to the design or operation of tanks inside the hull of a floating facility, as USCG requirements for tanks inside the hull of a unit may differ from BSEE requirements. Alternatively, the commenter suggested that the MOA should be revised to give USCG jurisdiction over the design of tanks that are integral to the hull and to give BSEE jurisdiction over non-integral tanks in the hull and over the operation of both integral and non-integral tanks in the hull of the unit that are for produced hydrocarbons, fuel and flow assurance fluids.

Response—The commenter is referring to tanks in the hull of a floating facility. BSEE agrees that the USCG has jurisdiction over the design and operation of tanks in the hull. However, under MOA OCS–04, BSEE has responsibility for regulation of the level safety systems on all product storage tanks, including those in the hull of a floating facility. These tanks are upstream of the production meters. BSEE does not regulate the tank design or how the operator loads the product. However, BSEE needs to ensure there is a safety system in place to ensure the tanks do not overflow. To clarify this issue, BSEE revised paragraph (a) in the final rule by deleting the proposed requirements for tanks with operating pressures less than 15 psig and by adding a specific reference to pressure vessels and fired vessels that are used to support production operations. Further discussion of BSEE's jurisdiction is found in part IV.B.2 of this document.

Pressure Vessels

Comment—One commenter noted that USCG has its own regulations regarding pressure vessels utilized in emergency and ship service systems for floating platforms. The commenter suggested that, for floating facilities, BSEE should state that the proposed regulations do not apply to pressure vessels, waste heat recovery, water heaters, piping or machinery that are associated with the unit's emergency and ship-service systems.

Response—As previously stated, this final rule applies only to operations that are under BSEE authority. Nonetheless, BSEE has revised final paragraph (a) to better delineate the scope of these provisions in relation to BSEE's authority.

Pressure Monitoring

Comment—A commenter questioned the need for continual monitoring in order to observe when the real time system pressure changes by 5 percent. The commenter asserted that most platforms are not equipped with a supervisory control and data acquisition/PLC (SCADA/PLC) type real-time monitoring system that could be programed to monitor and alarm a 5 percent change in operating pressure, although pressure safety high (PSH) and pressure safety low (PSL) safety devices constantly monitor pressure variables and are set to properly respond to an automatic detection of an abnormal condition. The commenter asserted that existing BSEE regulations allow the setting of PSHLs at 15 percent above/below the highest/lowest operating ranges in the production process and that installing equipment to monitor for a change of 5 percent would render the PSHLs redundant. The commenter stated that, currently, whenever PSHLs automatically detect abnormal conditions, the operating range at that time is evaluated to learn if a new range needs to be established. The commenter also asserted that the proposed rule did not offer a timeframe for establishing a new pressure range, and that such a timeframe should account for weather, schedules and other factors. The commenter expressed concern that the proposed requirement could result in nuisance shut-ins.

Response—BSEE does not agree with the suggestion that operators would need to acquire new real-time monitoring capabilities in order to implement the requirements of this provision. Section 250.851(b) does not require continuous real-time monitoring of pressure range; it only requires the use of pressure recording devices to establish new operating pressure ranges when an observed pressure change exceeds the limits specified in the rule. BSEE expects that operators are already using equipment that measures pressure changes in accordance with the existing regulations and industry standards and that is capable of being used under final § 250.851.

This provision does not preclude operators from setting new operating ranges based on a more conservative approach; that is, avoiding potentially unnecessary shut-ins by setting new pressure ranges when normalized system pressure changes by less than 50 psig or 5 percent. In addition, BSEE has clarified the final rule's requirements for resetting the pressure range, by adding language providing that once system pressure has stabilized, the operator must use pressure recording devices to establish the new operating pressure ranges. The final rule also specifies that the time interval for documenting the pressure range must be no shorter than 4 hours and no longer than 30 days. BSEE added the minimum time provision to ensure that the system pressure is stable before setting the operating ranges. In addition, the time period limitations were set, in part, because pressure spikes and/or surges may not be discernible in a range chart if the run time is too long. These revisions should also alleviate the commenter's concern regarding potential nuisance shut-ins.

Consistency With ASME Codes

Comment—A commenter stated that portions of proposed paragraph (a) were inconsistent with ASME's Boiler and Pressure Vessel Code and recommended revising the proposed rule to align with established codes. The commenter recommended specific language for revising proposed paragraphs (a)(1) and (a)(4).

Response—BSEE has revised this section in the final rule, as previously described, and the language the commenter suggested revising is no longer in the regulatory text.

Redundant Relief Valves

Comment—One commenter stated that, while this proposal attempts to account for the need to stagger relief valve set pressures, it could potentially create an unsafe condition, depending on the meaning of the term ''completely redundant relief valve'' in the proposed rule. The commenter noted that some equipment can have multiple causes for high pressure, each of which may produce different amounts of vapor that need to be relieved through the relief valve(s), and that it is not uncommon for some equipment to need multiple relief valves to meet various contingencies, while other equipment may only need a single relief valve. The commenter stated that making all the set pressures the same could lead to ''relief valve chatter'' (*i.e.,* the rapid opening and closing of the relief valve), with effects ranging from valve seal damage to valve or piping failure. The commenter suggested, in the case of a completely redundant or spare relief valve, that the set pressure should be the same as the valve it replaces and that the spare relief valve should be fitted with an inlet block valve. The commenter also suggested that if the primary relief valve needs to be isolated or removed, the spare relief valve/inlet block valve should be opened and the primary relief valve/inlet block valve closed for continuous protection. For those reasons, the commenter provided recommended revised language to provide for exceptions where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only.

Response—BSEE agrees with the commenter's reasoning for revising the exceptions language in proposed paragraph (a)(3) and has added the language suggested by the commenter as final paragraph (a)(3)(ii). The exceptions include cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only.

Operating Ranges

Comment—A commenter asserted that most operators do not monitor the operating ranges to see if pressures fluctuate by 5 percent, since such fluctuations do not typically indicate a change in the maximum operating pressure. The commenter opined that current industry practices for ensuring that pressures are below the maximum operating pressure are sufficient. To implement the proposed new requirement, the commenter asserted, industry would need to institute new field protocols, requiring additional resources, which would provide uncertain value. The commenter recommended revising the proposed provision to require establishment of new pressure ranges when the normal system pressure changes by the greater of 15 percent or 5 pounds per square inch (psi).

Response—BSEE revised paragraph (b) of this section to be consistent with similar requirements in other sections of the final rule (*e.g.,* final § 250.852), which also require the operator to establish new operating pressure ranges when the operating pressure changes by a specified threshold amount or percentage. BSEE disagrees with the commenter's suggestion for revising the proposed threshold for establishing new pressure ranges under this section. BSEE has determined that a 5 percent change in normalized system pressure is an appropriate threshold for requiring establishment of a new operating pressure range, since that threshold will help minimize nuisance shut-ins and provide operators with reasonable advance notice of potentially abnormal pressure changes that could pose safety or environmental risks. By using a 5 percent threshold, it is likely that operators will establish new operating pressure ranges more frequently than they would under a higher threshold (such as that suggested by the commenter). This should lead to fewer shut-ins that are due to pressure fluctuations that do not actually reflect a dangerous condition, but that would be above or below the pressure range that would have existed if it had not been reset under this provision. Conversely, the 5 percent threshold will provide operators with earlier warnings of potentially abnormal conditions, which could indicate an actual developing problem, and provide additional time and opportunity for the operator to take any appropriate steps to prevent a safety or environmental incident from occurring. The commenter's suggested threshold, by contrast, would not provide such opportunities, and therefore would not achieve the purposes of this provision.

For the same reasons (*i.e.,* minimization of nuisance shut-ins and early warning of potentially dangerous abnormalities), BSEE disagrees with the commenter's suggestion that the 5 percent threshold would not provide any value. In addition, to help clarify the requirements for establishing a new pressure range, BSEE added language to § 250.851(b) requiring that, after system pressure has stabilized, the operator use pressure recording devices to establish the new operating pressure ranges, and that the pressure range must be documented over time intervals that are no less than 4 hours and no more than 30 days long. This clarification will help minimize this commenter's concern that the 5 percent threshold will require new field protocols. In addition, contrary to the commenter's suggestion, setting sensors to monitor for a 5 percent change in pressure is not a new concept, since API RP 14 C, which is incorporated by reference in several sections of this final rule, already specifies that PSHL sensors be set with a pressure tolerance of 5 percent.

PSL Settings

Comment—A commenter noted that the proposed rule would require approval from the District Manager for activation limits on pressure vessels that have a PSL sensor set less than 5 psi, although some pressure vessels currently operate below 5 psi. The commenter suggested that BSEE delete this requirement because it would create an unnecessary administrative burden.

Response—BSEE did not make any significant changes to the final rule. Setting the PSL sensor below 5 psig requires approval from the District Manager because, in BSEE's experience, pneumatic-type sensors are generally less accurate when pressure is below 5 psig. While the commenter asserts that the requirement would create an unnecessary administrative burden, the commenter did not provide any further information about this asserted burden. If the commenter was referring to burdens on BSEE's District Managers, BSEE does not agree that any such burden would be unnecessary or unwarranted given BSEE's need to ensure that pressure vessels are operating safely. If the commenter was referring to an administrative burden on operators, the commenter did not provide any estimate of that burden.

Flowlines/Headers (§ 250.852)

Section summary—The final rule moves the content of existing § 250.803(b)(2), which establishes requirements for flowlines and headers, to final § 250.852. The existing regulations require the establishment of new operating pressure ranges at any time a ''significant'' change in operating pressures occurs. The final rule specifies instead that the operator needs to set new operating pressure ranges for flowlines any time the normalized system pressure changes by 50 psig or 5 percent, whichever is greater. The final rule also specifies relevant timing and procedures. BSEE also added requirements for wells that flow directly to a pipeline without prior separation and for the closing of SSVs by safety sensors, as well as requirements for choking devices, and for the use of single valves and sensors to protect multiple subsea pipelines or wells that tie into a single pipeline riser.

Regulatory text changes from the proposed rule—Proposed paragraph (a)(2) was revised in the final rule to clarify the requirements for establishing new operating pressure ranges in response to comments on similar provisions in proposed § 250.851 and other sections. Final paragraph (b) was revised to clarify that initial set points for pressure sensors must be set using gauge readings and engineering design. In final paragraph (c)(1), the word ''liquid'' was removed after the phrase ''maximum-anticipated flow of'' so as not to improperly limit the scope of the requirement.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Nuisance Shut-Ins

Comment—A commenter asserted, as an example, that under the proposed regulations, a flowline that has a normalized operating range of 50 psig would have a PSH setting of 57 psig and a PSL setting of 43 psig. The commenter then explained that if the operating range normally changes to 40 psig, due to a naturally depleting well, the PSL will actuate and shut-in the well unnecessarily. The commenter also asserted that the operator would not be able to establish a new pressure range since the change was not ''50 psig or 5 percent, whichever is higher.'' Therefore, the well would remain shut-in until the range changed by the greater of 50 psig or 5 percent. Thus, the commenter concluded that the proposed regulation would not provide for normalized operating ranges that are below 1,000 psig (since 5 percent of 1,000 psig is 50 psig). The commenter also asserted that BSEE currently permits operators to establish new operating ranges at less than the proposed change requirements of 50 psig or 5 percent, whichever is greater,'' to help prevent nuisance shut-ins.

Response—As discussed in regard to similar comments on proposed § 250.851, operators may use a more conservative approach to help prevent nuisance shut-ins, by using a lower change in pressure than that specified in this section (*i.e.,* the greater of 50 psig or 5 percent) as a threshold for establishing a new operating pressure range. The thresholds established by §§ 250.851 and 250.852 represent pressure changes at which an operator must establish new operating pressure ranges; they do not preclude an operator from establishing new operating pressure ranges based on pressure changes below those thresholds. BSEE has added language to the final that states that once system pressure has stabilized, the operator must establish the new operating pressure ranges using pressure recording devices that document the pressure range during time intervals no less than 4 hours and no more than 30 days long.

Consistency With Subpart J

Comment—A commenter asserted that the proposed language conflicts with the current language in subpart J, and also with the recommended guidance in API RP 14C. The commenter recommended deleting the requirement for the PSV when the shut-in tubing pressure is greater than 1.5 times the maximum allowable working pressure (MAWP) of the pipeline or flowline. The commenter stated that, currently, with the two SSVs with independent PSHs, a safety integrity level (SIL) of 2 is achieved when both SSVs are required to hold bubble tight (zero leakage). The second SSV serves as an alternate safety device to prevent over pressurization of the pipeline.

Response—No changes are necessary, since this section covers only the safety systems on the pipeline, which are part of the production safety system. BSEE regulations do not address or rely on the SIL approach. Although BSEE does not agree that there is a conflict between API RP 14C, as referenced in this section of the final rule, and subpart J, if there is any conflict between any industry standard and any regulation in subparts H or J, operators must follow the regulations. In addition, if there is any conflict between the requirements of subparts J and H, operator must follow the more rigorous requirement, which generally will found in subpart H. . Although BSEE is not aware of a conflict between these final subpart H requirements, API 14C, and subpart J, BSEE will continue to monitor the implementation of both sets of requirements to ensure there are no conflicts. Further, if an operator believes there may be a conflict in a particular situation, the operator may contact the District Manager for advice.

Applicability to Subsea Installations

Comment—A commenter suggested revising the section title of proposed § 250.852 so that the section applies only to dry trees on floating facilities and expressly limiting this section to surface trees and dry well jumper flowlines to avoid confusion with subsea installation which requires different equipment.

Response—BSEE disagrees with the suggestions for revising the section title and for limiting this section to surface trees and dry well jumper flowlines. The requirements in this section apply to all dry trees, except for paragraph (e), which applies to dry trees on floating facilities, and paragraph (g), which applies to pipeline risers on floating production facilities. The requirements for other safety devices that are used for subsea installations are addressed in §§ 250.873 through 250.875 of the final rule. Thus, BSEE does not agree that the organization of the sections in the final rule is likely to cause any confusion as to requirements for dry trees and subsea installations.

Normal Variations in Operating Pressures

Comment—A commenter suggested revising the language of proposed § 250.852(a)(2), since slugging and other dynamic phenomenon that may be associated with normal flow can often cause the pressure to fluctuate by 5 percent or more. The commenter noted that normalized operating pressure may include variations that are associated with transient or dynamic conditions, such as gas surge from multi-phase slugging during normal operations. The commenter requested clarification as to the requirement to reestablish an operating pressure range when normalized operating pressure changes by 5 percent. The commenter also recommended modifying § 250.852(a)(2) to require pressure recording devices to be used to establish new operating pressure ranges for required flowline or header PSH/PSL sensors at any time the normalized operating pressure changes are outside the parameters of § 250.852(b)(1).

Response—As previously discussed, BSEE has determined that the 5 percent (or 50 psig, whichever is greater) threshold is appropriate because it will both help prevent nuisance shut-ins (through more frequent resetting of operating pressure ranges) and provide earlier warning of potentially dangerous conditions that may require action to prevent a safety or environmental incident. In addition, the 5 percent threshold is consistent with the 5 percent level pressure tolerance levels for PSHL sensors under API RP 14C. (However, if any operator believes that its operating pressures may change by more that 5 percent under normal flow conditions, and that it should use a different threshold for establishing a new pressure range, it may request approval for use of an alternate procedure under existing § 250.141.) As requested by the commenter, however, BSEE has clarified the revised final paragraph (a)(2) to provide additional clarity regarding the use of pressure recording devices to establish new operating pressure ranges.

Relief Valves

Comment—A commenter suggested revising the language of proposed § 250.852(c)(1) to allow for a relief valve which vents into the platform flare scrubber or some other location approved by the District Manager that is designed to handle, without liquid-hydrocarbon carry-over to the flare, the maximum anticipated flow of hydrocarbons that may be relieved to the vessel.

Response—BSEE agrees with this comment and has revised the final regulation, by removing the word ''liquid'' to ensure the flare scrubber is designed to handle the maximum anticipated flow of all hydrocarbons.

Qualification Tests

Comment—A commenter suggested revising the language in proposed § 250.852(e)(1) to allow designs to be verified through qualification tests since flexible design methodology is proprietary and the manufacturers will not release the design methodology to an independent verification agent (IVA).

Response—The suggested changes are not necessary. The design methodology is contained in API Spec. 17J, Specification for Unbonded Flexible Pipe, which has already been incorporated in existing § 250.803 for flowlines on floating platforms, and which is nearly identical to the requirements contained in final § 250.852(e)(1). The existing regulation, like this final rule, specifies the type of manufacturer documentation, such as design reports and IVA certificates, that operators must review. BSEE is not aware that the concern raised by the commenter has been a significant issue under the existing regulations.

Pipeline Risers

Comment—A commenter requested clarification on this section, asserting that the proposed requirements in paragraphs (g) and (h) were somewhat unclear since they first refer to a ''single pipeline riser'' on the platform and then refer to ''each riser'' on the platform.

Response—No changes are necessary. Both paragraphs (g) and (h) address situations involving multiple subsea sources (wells or pipelines) that tie into a single pipeline riser or multiple risers on a platform. If a single flow safety valve (FSV) on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser, each riser may have its own FSV (as provided by paragraph (g)) and its own PSHL (as provided by paragraph (h)).

Safety Sensors (§ 250.853)

Section summary—The contents of existing § 250.803(b)(3), pertaining to safety sensors, have been moved to final § 250.853, and revised for clarity and to use plain language. This section requires that all shutdown devices, valves, and pressure sensors function in a manual reset mode; that sensors with integral automatic resets be equipped with appropriate devices to override the automatic reset mode; and that all pressure sensors be equipped to permit testing with an external pressure source.

Regulatory text changes from the proposed rule—BSEE deleted the proposed requirement that all level sensors on new vessel installations be equipped to permit testing through an external bridle.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Level Sensors on External Bridles

Comment—A commenter asserted that the proposed requirement, in paragraph (d), that level sensors be located on an external bridle (rather than directly on the vessel) is unnecessary, as long as a means of testing the sensor without a level bridle is available. The commenter stated that fouling or foaming services may cause external bridle sensors to misread levels in some services. The commenter added that certain sensor testing technologies (*e.g.,* ultrasonic and capacitance) are not suitable for use in external bridles, and that some proposed or new projects are evaluating using ultrasonic, optical, microwave, conductive, or capacitance sensors. However, the commenter asserted, that these sensors do not utilize bridles. The commenter requested that BSEE remove paragraph (d) from the new regulations or revise this section to allow for new sensor technology that does not utilize bridles.

Response—BSEE disagrees with the commenter. Sensor testing equipment built according to API standards, which are incorporated by reference into BSEE's regulations, should be able to meet this provision. Moreover, an operator that wants to use alternate technology that is incompatible with bridles can propose alternate approaches through the DWOP process or seek approval from BSEE under § 250.141. BSEE does not need to refer to those options in this section. However, BSEE has removed proposed paragraph (d) from the final rule because BSEE can address level sensors adequately using existing regulatory processes, such as the DWOP, and we do not need to specify uses and conditions of such sensors in this regulation.

Floating Production Units Equipped With Turrets and Turret-Mounted Systems (§ 250.854)

Section summary—Final § 250.854 establishes a new requirement for floating production units equipped with turrets and turret-mounted systems. The operator will be required to integrate the auto slew system with the safety system, such that the production processes automatically shut-in and release the buoy. Specifically, the safety system must immediately initiate a process system shut-in, in accordance with final §§ 250.838 and 250.839, and release a buoy to prevent a spill and damage to the subsea infrastructure when the auto slew mode is activated and there is a ship heading/position failure or the rotational limits of the clamped buoy are exceeded.

This new section will also require floating production units with swivel stack arrangements to be equipped with a leak detection system for the portion of the swivel stack containing hydrocarbons. The leak detection system will be required to be tied into the production process surface safety system allowing for automatic shut-in of the system.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section in the final rule.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Performance Standards for Leak Detection

Comment—A commenter acknowledged that leak detection requirements for floating productions units are an improvement, but asserted that BSEE should prohibit the use of floating production units for long-term production in the Arctic OCS.

Response—BSEE disagrees with prohibiting the use of floating production units for long-term production in the Arctic as this would prematurely, and potentially unnecessarily, limit long-term options for development in the Arctic. Moreover, an operator must demonstrate that any proposed production unit is suitable for its operating environment. Under final § 250.800(a), all oil and gas production safety equipment must be designed, installed, used, maintained, and tested to ensure the safety and protection of the human, marine, and coastal environments. Final § 250.800(a) also requires that, for production safety systems operated in subfreezing climates, the operator must account for floating ice, icing, and other extreme environmental conditions that may occur. In addition, as previously discussed, BSEE may address Arctic-specific issues in future rulemakings, guidance or other documents.

Riser Disconnects

Comment—A commenter stated that the mooring is designed to retain a vessel on location and protect the risers, which should be flushed and/or purged prior to disconnect during a planned process. The commenter then asserted that the proposed requirements in this section could reduce the safety of that system.

Response—BSEE does not agree with the suggestion that the requirements in this section could make the disconnect system less safe. However, BSEE recognizes that, for each floating production system with disconnectable turrets and a turret-mounted system, the system configuration and disconnect process will be unique. BSEE also understands that there are distinctions between an emergency disconnect and a planned disconnect, and that there are personnel safety concerns during any disconnect that the operator must address. Accordingly, BSEE will continue to evaluate the disconnect process on a case-by-case basis as part of the initial planning and review of a facility's plans and systems under a DWOP. In addition, as a condition of approval in the DWOP, BSEE may require the operator to demonstrate the disconnect system once per year.

Leak Detection

Comment—A commenter suggested revising the language of proposed § 250.854(b), asserting that, on many swivel stacks with leak detection systems, the rate of a hydrocarbon leak, not the detection of a hydrocarbon leak, is the criterion for an automatic shut-in.

Response—BSEE does not agree that the commenter's recommended changes are necessary. While BSEE agrees that the use of some type of system to detect and contain a leak is appropriate, a catastrophic failure must initiate a process system shut-in. However, a seal failure that causes a leak into the production system, which is contained, will not require an automatic shut-in. This provision protects against a scenario in which those internal seals have failed in such a way that a leak external to the production system (*i.e.,* a containment failure) occurs. This is an abnormal condition and, to protect safety and the environment, the system needs to automatically sense such a leak and shut-in.

Emergency Shutdown (ESD) System (§ 250.855)

Section summary—The contents of existing § 250.803(b)(4), pertaining to ESD systems, have been moved to final § 250.855. Existing § 250.803(b)(4) provides that only ESD stations at a boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve. The final rule clarifies that the breakable loop in the ESD system is not required to be physically located on the boat landing; however, in all instances it must be accessible from a vessel adjacent to or attached to the facility. The final rule also requires that a schematic of the ESD, indicating the control functions of all safety devices for the platforms, must be kept on the platform, at the field office nearest the OCS facility, or at another location conveniently available to the District Manager for the life of the facility.[23] The final rule also introduces requirements for electronic ESD stations and ESD components.

Regulatory text changes from the proposed rule—BSEE revised paragraph (a) in the final rule to clarify requirements of the ESD stations, to ensure the stations function and are identified properly. BSEE also revised this paragraph to respond to comments and to better align the regulation with incorporated standards. As provided in section C.1 of API RP 14C, incorporated in this section, the final rule also requires that: the electric ESD stations be wired as ''de-energize to trip'' circuits or as supervised circuits; all ESD components be high quality and corrosion resistant; and ESD stations be uniquely identified. BSEE also clarified the proposed requirement that a breakable loop, if one is used, be accessible ''from a boat;'' the final regulation requires that the breakable loop must be accessible ''from a vessel adjacent to or attached to the facility.''

[23] The purpose of the full ESD schematic is to enable BSEE to confirm the design. This detailed schematic is not the same as the safety equipment and layout drawing that indicates the locations of the ESD stations and that is submitted to BSEE with production system applications. BSEE expects that a copy of the safety equipment and layout drawing will continue to be retained on the floating production facility for potential use by first responders or others in an emergency.

Comments and responses—BSEE received one comment on this section and responds as follows:

ESD on Boat Landings

Comment—A commenter stated the proposed rule references only pneumatic-type valves, while current technology incorporates electronic switching devices. The commenter asserted that an ESD device on a boat landing can be either a breakable loop for pneumatic systems or a stiffen ring on an electronic switch that can be actuated using a boat hook.

Response—BSEE agrees with the commenter's observation that the proposed rule was limited to pneumatic-type valves and did not address the boat landing ESD. In the final rule, BSEE has revised this section to better reflect relevant language in the incorporated API RP 14C (section C.1) and to require that the ESD stations be uniquely identified. Because it is critical that the ESD stations be clearly recognizable and functional during an emergency, BSEE wants to emphasize this requirement.

Engines (§ 250.856)

Section summary—The requirements in existing § 250.803(b)(5), pertaining to engine exhaust and diesel engine air intake and shutdown devices, have been moved to final § 250.856 and rewritten for clarity and plain language. BSEE also clarified this section of the final rule by listing the types of diesel engines that do not require a shutdown device .

Regulatory text changes from the proposed rule—BSEE added the parenthetical ''(*i.e.,* overspeed)'' after the word ''runaway'' in final paragraph (b) to clarify what is meant by a runaway, since the term ''overspeed'' is commonly used and understood in the marine industry.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Mechanical Air Intake Device

Comment—A commenter stated that diesel engines usually have an overspeed device that will shut down the run-away engines except when a firewater pump and emergency generator is started due to an emergency shutdown or confined entry air supply. The commenter then asked whether this section would require use of a mechanical air intake device in addition to the overspeed sensor.

Response—Overspeed sensors are always required,. In addition, under final § 250.856, the operator must equip diesel engine air intakes with a device to shutdown the engine in the event of a runaway (*i.e.,* overspeed), except for certain identified categories of diesel engines. The final rule also requires that diesel engines that are continuously attended be equipped with either remotely-operated manual or automatic shutdown devices and that diesel engines that are not continuously attended be equipped with automatic shutdown devices.

Jurisdiction

Comment—A commenter recommended that paragraph (b) of this section be limited to fixed platforms only. According to the commenter, under item 12 of MOA OCS–04 between the Minerals Management Service (MMS) (now BSEE) and the USCG, firefighting safety equipment and systems on floating offshore facilities are under the responsibility of the USCG, as are requirements for emergency power sources on floating offshore facilities.

Response—As previously explained, these regulations only apply to operations that are under BSEE authority. In addition, paragraph (b) is essentially a recodification of longstanding BSEE regulations, under which the commenter's jurisdictional questions have not proven to be an issue.

Glycol Dehydration Units (§ 250.857)

Section summary—The final rule moves the contents of existing § 250.803(b)(6), pertaining to safe operations of glycol dehydration units, to final § 250.857. The final rule adds new requirements for FSVs and shutdown valves (SDVs) on the glycol dehydration unit.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Venting the Glycol Regenerator

Comment—One commenter noted that the proposed regulations require the installation of a pressure relief valve on the glycol regenerator (reboiler) to prevent over-pressurization, and require that valve to be vented in a non-hazardous manner. The commenter suggested that the regulation should provide specific instructions on how the operator can vent the glycol regenerator in a non-hazardous manner. The commenter also noted that BSEE requested additional comments on opportunities to limit emissions from OCS production equipment. The commenter recommended that BSEE require emission control systems to be installed on OCS glycol dehydration units or require the use of desiccant dehydrators (where technically feasible). The commenter also recommended that the regulations be revised to require OCS operators to install flash tank separators, optimize the glycol circulation rate, and reroute the skimmer gas.

Response—The provision of the final rule requiring that the relief valve discharge must be vented in a non-hazardous manner is a recodification of longstanding BSEE regulations. The commenter is asking instead for a prescriptive requirement on how the operator should vent the glycol regenerator in a non-hazardous manner. There are many ways this can be accomplished. The commenter itself described three different approaches to achieving this. However, BSEE does not want to limit the options to just a few approaches; rather, the final rule sets a performance goal and allows the operator to decide the best approach to achieve the required goal. This performance-based approach, involving the same standards, has worked under the existing regulation.

BSEE appreciates the commenter's recommendations regarding emissions controls and will consider them. BSEE may also consider additional measures, such as emission control systems, in the future to ensure safety and protect the environment; however, those measures are outside the scope of this rulemaking.

Safety Devices

Comment—One commenter stated that the proposed rule listed some, although not all, safety devices for equipment specified in API RP 14C, which allows operators to rebut the need for some safety devices according to safety analysis checklists The commenter asserted that the requirements in this proposed regulation may restrict that option. The commenter suggested deleting these requirements and referencing the requirements in API RP 14C, as in proposed § 250.865(a). The commenter also suggested that the requirement in proposed § 250.857(c) regarding installation of the SDV should be required only for new designs or modifications to glycol dehydration units.

Response—No changes to the final rule are necessary. Requiring two valves on the glycol dehydration units, as proposed, helps ensure safety of the operations. The requirements of this section are in addition to API RP 14C, which requires a shutdown valve, but does not specify the location of the shutdown valve. The final rule requires that the shutdown valve be installed as near as practical to the glycol tower, to ensure safety and protect the environment. Placing the shutdown valve closer to the glycol tower reduces the amount of product that may be released to the environment in the event of damage to the system.

Gas Compressors (§ 250.858)

Section summary—BSEE moved the contents of existing § 250.803(b)(7), pertaining to gas compressor operations, to final § 250.858. BSEE also revised those provisions for clarity and plain language. Final paragraph (a) establishes certain equipment requirements consistent with API RP 14C for gas compressors. Paragraph (b) requires the use of pressure recording devices to establish a new operating pressure range after an operating pressure change greater than 5 percent or 50 psig, whichever is higher. Final paragraph (c) contains a table of pressure sensor shut-in settings.

Regulatory text changes from the proposed rule—Based on comments received, BSEE revised final paragraph (a)(2) to clarify that the temperature safety high (TSH) must be equipped in the discharge piping of each compressor cylinder or case discharge. BSEE also revised final paragraph (b) to clarify the requirements for establishing new operating pressure ranges after specified pressure changes, consistent with other sections of the final rule, in response to comments seeking clarification on the subject.

After consideration of various issues raised by commenters, BSEE omitted proposed paragraph (c), which would have provided an exception to the installation of PSHs and PSLs for vapor recovery units (VRUs) when the system is capable of being vented to the atmosphere, from the final rule.

BSEE added a new paragraph (c) to the final rule that includes the contents of proposed paragraphs (b)(1) through (b)(3). New paragraph (c) also clarifies that initial set points for pressure sensors must be set utilizing gauge readings and engineering design. These changes were made to make the requirements for operating pressure ranges and pressure sensors consistent with similar provisions in other sections of the final rule.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Temporary Flaring of Gas-Well Gas

Comment—A commenter suggested revising the language in proposed § 250.858(a)(3) to allow temporary flaring of gas-well gas in the event of an upset condition within allowable flare limits. The commenter suggested that gas-well gas affected by the compressor's closure of the automatic SDV could be shut-in manually or temporarily diverted to a flare if compliant with §§ 250.1160 through 250.1161.

Response—As the commenter noted, temporary flaring of gas-well gas is directly addressed in part 250, subpart K (§§ 250.1160 and 250.1161), which sets the conditions for flaring or venting gas-well gas. However, after consideration of issues related to this comment, BSEE agrees with the commenter that allowing gas-well gas to be flared or vented in the event of an upset condition with a gas compressor can be done consistently with existing §§ 250.1160 and 250.1161. Accordingly, BSEE has changed the language in final § 250.858(a)(3) to clarify that gas-well gas can be diverted to flare or vent in accordance with the requirements §§ 250.1160 and 250.1161.

However, BSEE has deleted proposed paragraph (c), which would have created a general exception to the installation of PSHs and PSLs for VRUs when the system is capable of being vented to the atmosphere. BSEE deleted that proposed exception because, after considering all the issues raised by commenters, BSEE realized that, for some VRUs, the volume of gas from the tank could create a suction pressure exceeding 5 psig, resulting in an over-pressure that could cause the VRU to burst. Therefore, BSEE decided that it needs to confirm that the system is operating at 5 psig before approving a system that could be vented to the atmosphere without a PSH and PSL installed.

Compressor Skids

Comment—A commenter noted that the proposed regulation did not compensate for lower operating ranges throughout the compressor skid, especially when considering VRUs. The commenter noted that it is highly unlikely that a VRU would have an operating change of 50 psig or greater and expressed concern that the proposed requirement for compressor discharge sensors did not provide for normalized operating ranges. The commenter questioned the purpose of the proposed rule, since the commenter asserted that operators are currently permitted by BSEE to establish new operating ranges at less than the proposed pressure change threshold of 50 psig or 5 percent, whichever is greater, to help prevent nuisance shut-ins.

Response—BSEE disagrees with the suggestion that this regulation will not help prevent nuisance shut-ins. As previously discussed in response to similar comments, establishing new normalized operating pressure ranges, whenever actual operating pressure changes by the amounts specified in this provision, will help prevent nuisance shut-ins. Operating pressure ranges need to be re-established periodically, and sensors need to be reset to reflect normal changes in operating pressures. If not, shut-ins are more likely to occur because the unadjusted pressure range and sensors could indicate an abnormal condition when a pressure change would otherwise be considered routine and within the adjusted pressure range. In addition, as previously explained, BSEE has set the threshold for requiring the establishment of new pressure ranges at levels that provide a reasonable safety cushion. However, BSEE agrees with the commenter in that an operator may choose to set a pressure change threshold below 50 psig or 5 percent in order to re-set the normalized operating pressure range more frequently (and thus further reduce the possibility of a nuisance shut-in) than would otherwise be required under this regulation.

Centrifugal Compressors

Comment—A commenter noted that the proposed section used language suggesting that it would apply to devices on reciprocating compressors and recommended that BSEE include an additional section for centrifugal compressors since they appear to comply with API RP 14C as well.

Response—BSEE revised this section to better conform to the language of API RP 14C which does not distinguish between the different types (*i.e.,* centrifugal or reciprocating) of compressors. The determination as to the types of protective equipment required under API RP 14C applies regardless of the type of compressors. If a specific installation does not meet the criteria for a defined gas compressor component under API RP 14C, the operator should consult the District Manager to determine what equipment under API RP 14C is required.

Firefighting Systems (§ 250.859)

Section summary—BSEE moved the contents of existing § 250.803(b)(8), pertaining to firefighting systems, to final §§ 250.859, 250.860, and 250.861

and revised the existing requirements to include a number of additional requirements, including several provisions contained in NTL No. 2006–G04, ''Fire Prevention and Control Systems.''

Final § 250.859(a) clarifies the requirements for firefighting systems on fixed facilities only, and includes requirements from existing § 250.803(b)(8)(i) and (ii), as proposed. Final paragraph (a) also requires, as proposed, that within 1 year after publication of the final rule, operators must equip all new firewater pump drivers with capabilities for automatic starting upon activation of the ESD, fusible loop, or other fire detection systems. Final paragraph (a) also requires that, for electric-driven firewater pump drivers, operators must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time in the event of a loss of primary power. The final rule also specifies requirements for routing power cables, or conduits with wires installed, between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement.

Final paragraphs (a)(3) and (4) include the requirements of former § 250.803(b)(8)(iv) and (v) regarding firefighting system diagrams and subfreezing climate suitability, respectively. Final paragraph (a)(5) requires operators to obtain approval from the District Manager before installing any firefighting system. Final paragraph (a)(6) requires that all firefighting equipment located on a facility be in good working order.

Final paragraph (b) was added to clarify the requirements for firewater systems to protect all areas where production-handling equipment is located on floating facilities. This section also requires the operator to install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate and provides that the firewater system must conform to applicable USCG requirements.

Final paragraph (c) specifies that if an operator is required to maintain a firewater system which becomes inoperable, the operator either must shut-in its production operations while making the necessary repairs or, for fixed facilities, request that the appropriate District Manager grant a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis for a period up to 7 days while the necessary repairs to the firewater system are made. This paragraph also clarifies that, for fixed facilities, if the operator is unable to complete repairs during the approved time period because of circumstances beyond its control, the District Manager may grant extensions to the approved departure for periods up to 7 days.

Regulatory text changes from the proposed rule—This section was revised, based on comments received, to clarify that it applies to facilities and areas subject to BSEE authority, as explained in the following responses to specific comments. In addition, the word ''BSEE'' was removed before the ''District Manager'' throughout the section for consistency and because it was superfluous. BSEE also reworded and reorganized several provisions for greater clarity and to avoid ambiguity and potential confusion.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Redundancy in Firefighting Systems

Comment—A commenter noted that firefighting systems have redundancy and that they can be fully functional, and redundant, even when some equipment is down for repair. The commenter asserted that this rule should make provisions for this to avoid a facility being deemed out of compliance when some components of the firewater system are being repaired, even though the system as a whole is still functional.

Response—BSEE disagrees. To safely conduct operations the firefighting systems must be fully functional. Redundancy is required in case the system fails when needed, not to provide coverage for repairs.

Jurisdiction for Fire Protection and Firefighting Systems

Comment—A commenter asserted that, for both fixed and floating facilities, USCG has jurisdiction over most of the fire protection, detection, and extinguishing system areas, except for the production handling area. The commenter suggested that the regulations should be limited to this area only, and that any proposed requirements for firefighting in other areas, including well bays, should be removed, along with requirements for fire water pumps. The commenter also requested that all discussion of firewater systems, chemical firefighting systems, and foam systems should be clarified to state that they apply only to the production-handling area. The commenter asserted that USCG has jurisdiction for fire and smoke detection, so those requirements should be limited to interfaces with BSEE systems (such as the ESD system).

Response—This comment was also made in reference to §§ 250.842 and 250.861. As discussed in response to other comments, BSEE's regulations apply only to operations and systems that are under BSEE's authority. (*See* discussion in part IV.B.2 of this document regarding BSEE's jurisdiction under the heading ''BSEE and U.S. Coast Guard (USCG) Jurisdiction,'' including discussion of BSEE–USCG MOAs describing situations in which BSEE and USCG share responsibility for various aspects of firefighting.)

To further clarify this point, BSEE has revised paragraph (a) in the final rule so that the requirements expressly apply to areas where production-handling equipment is located on fixed facilities. BSEE also revised final paragraph (b) to clarify that the requirements in that paragraph apply to areas on floating facilities where production-handling equipment is located. In addition, final paragraph (b) requires the firewater system to conform to USCG requirements for firefighting systems on floating facilities. Further, BSEE revised final paragraph (c) to clarify that the provision allowing an operator to request permission from BSEE to temporarily use a chemical firefighting system, in the event the firewater system becomes inoperable, applies to fixed facilities only. In addition, as discussed in part IV.C, BSEE has revised the firefighting-related requirements of final §§ 250.859 through 250.862 to further clarify that they apply to areas and systems under BSEE's authority, and to confirm that operators must also comply with applicable USCG regulations. Section 250.842 already clearly states that it applies to the production safety system.

Arctic Requirements

Comment—A commenter suggested that BSEE work with Arctic firefighting experts to develop firefighting system regulations to address suppression of hazardous material, electrical, flammable liquid, and combustible liquid fires that may occur at Arctic OCS operations and that BSEE should include those requirements in the regulation. The commenter noted that BSEE proposed a number of improvements to firefighting systems for OCS operations, including a proposed improvement at § 250.859 that requires OCS facilities to be shut-in if the firewater system becomes inoperable. However, the commenter asserted that the regulations do not appear to address specific firefighting requirements needed for the Arctic. The commenter stated, as an example, that wet pipe fire water systems (*i.e.,* systems continuously charged with fire water) are not used in Arctic operations because of the risk of freezing and pipe burst. The commenter also discussed the potential advantages of dry pipe, dry chemical, and dry powder fire extinguishing systems.

Response—BSEE understands that the Arctic may present unique operating conditions. Final § 250.859(a)(4) includes firewater system requirements for operations in subfreezing climates, including a requirement to submit evidence demonstrating that the firefighting system is suitable for subfreezing conditions. Any permit application must address the specific operating conditions where the activity is taking place, and BSEE considers those conditions when reviewing a permit application. Any firefighting system proposed for use in the Arctic OCS, must be able to perform in the environmental conditions found in the Arctic. Specific requirements for chemical firefighting systems are found in § 250.860 of this rulemaking. However, as already explained in response to other comments, BSEE expects to address other Arctic-specific issues in the future through a variety of mechanisms, potentially including separate rulemakings, guidance, or other documents.

Redundant Power Source

Comment—A commenter asserted that BSEE would be correct to require an alternative power source for firefighting systems because, if the main engine room, the main engines, or associated power cables are disrupted by fire, the firefighting systems may become inoperable. The commenter asserted that an alternative power source, preferably placed in a location separate from the main engine room should be available to provide alternative power to firefighting equipment during an emergency.

Response—BSEE generally agrees with the comment and has finalized paragraph (a)(2) with only minor wording and organizational changes. BSEE notes that, if an electric firewater pump is based on a fuel gas system, the personnel on the facility may not have adequate time for egress if they need to shut down the generator. Accordingly, the final rule requires an emergency power source with an automatic transfer switch and requires that fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. The operator must also install an alternate fuel or power supply to provide for this pump operating time, if needed. This is consistent with the provisions in the proposed rule.

API RP 14G and Floating Facilities

Comment—A commenter agreed that the inclusion of certain proposed provisions would enhance safety, but asserted that the incremental benefits of incorporating all of API RP 14G standard would not justify the increased costs. The commenter stated that API RP 14G does not offer a ''cookbook'' method of designing and installing a complete firefighting system; instead, API RP 14G offers recommended criteria for whatever firefighting system the operator chooses to install. The commenter asserted that the proposed rule did not account for existing systems that were approved under the current regulations and under current approval and inspection policies. The commenter also asserted that the proposed rule did not take into account potential conflicts with USCG firefighting requirements for floating facilities.

The commenter recommended that BSEE separate firefighting requirements for fixed facilities from those for floating facilities since the latter are driven mainly by the USCG. The commenter also recommended revisions to clarify the separate requirements for fixed facilities and floating facilities and to account for currently approved systems in service.

Response—BSEE agrees with several of the commenter's recommended changes and has revised this section accordingly. BSEE also revised final paragraph (a) to state that the ''firewater system'' on fixed facilities must conform to API RP 14G, in order to clarify that compliance with API RP 14G is required only for the firewater systems and not for all firefighting systems, as implied by the proposed language. (This revision is also consistent with the existing regulations.)

As suggested by the commenter, BSEE also revised the final rule to clarify the separate requirements for firefighting systems on fixed facilities and floating facilities. These changes help ensure that there are no conflicts with the USCG for firefighting systems by focusing this final section on areas where production-handling equipment is located and on enclosed well-bay areas where hydrocarbon vapors may accumulate, and by referring to the need to comply with USCG requirements for floating facilities.

Chemical Firefighting System (§ 250.860)

Section summary—Existing § 250.803(b)(8)(iii) allows the use of a chemical firefighting system in lieu of a water-based system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control. Final § 250.860 recodifies this concept and includes a number of additional details from NTL No. 2006–G04 in order to update BSEE's regulations pertaining to firefighting. This final rule specifies requirements regarding the use of chemical-only systems on fixed platforms; specifically, major platforms, minor manned platforms, or minor unmanned platforms. The final rule also defines the terms ''major,'' ''minor,'' ''unmanned,'' and ''manned'' platforms.

Final § 250.860(a) addresses the potential use of a chemical-only firefighting system, in lieu of a water-based system, on any fixed platform that is both minor and unmanned. Final paragraph (a) authorizes the use on such platforms of either of two types of portable dry chemical units, as long as the operator ensures that the unit is available on the platform when personnel are on board. A facility-specific authorization from BSEE would not be required under this paragraph.

Paragraph (b) of the final rule allows use of a chemical firefighting system, in lieu of a water-based system, on any fixed major platform or minor manned platform, if the District Manager determines that the use of a chemical-only system provides equivalent fire-protection control and would not increase the risk to human safety. To provide a basis for the District Manager's determination that the use of a chemical system provides equivalent fire-protection control, final paragraph (c) requires an operator to submit a justification addressing the elements of fire prevention, fire protection, fire control, and firefighting on the platform. Final paragraph (c) also requires the operator to submit a risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. That paragraph lists the items that the operator must include in the risk assessment.

Final § 250.860(d) addresses the documentation that an operator must maintain or submit for the chemical firefighting system. This paragraph also clarifies that, after the District Manager approves the use of a chemical-only fire suppressant system, if the operator intends to make any significant change to the platform (such as placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment, or planning to man an unmanned platform), the operator must seek BSEE District Manager approval.

Regulatory text changes from the proposed rule—BSEE revised this section to clarify that it applies only to fixed platforms. Throughout this section, ''BSEE'' was removed before ''District Manager'' for consistency. In addition, BSEE reorganized and restructured the final rule to make it clearer and easier to understand.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Limit to Fixed Platforms

Comment—A commenter recommended that this paragraph be limited to fixed platforms only because, in accordance with item 12 of the MOA OCS–04 between MMS (now BSEE) and the USCG, firefighting safety equipment and systems on floating offshore facilities are the responsibility of the USCG.

Response—As already explained in response to other comments, BSEE's regulations only apply to operations that are under BSEE authority. However, BSEE has added language to the beginning of this section in the final rule to clarify that it applies to fixed platforms only. (*See* part IV.B.2 for a more detailed discussion of BSEE's and USCG's jurisdiction.)

Risk Assessment Criteria

Comment—A commenter asserted that BSEE was proposing to codify existing NTL No. 2006–G04, but that the proposed rule did not indicate how the proposed risk assessment criteria will be evaluated. The commenter understands that BSEE developed a risk matrix for use in evaluating an operator's risk assessment. The commenter recommended that BSEE include the risk matrix with the risk assessment criteria in the final rule in order to save both the operator and BSEE time in preparing and reviewing, the request.

Response—No changes are necessary. The final rule includes the categories of information required for BSEE's risk assessment from NTL No. 2006–G04, ''Fire Prevention and Control Systems.'' The operator must address those categories; however, BSEE does not believe it is necessary or appropriate to include the requested details in this final rule. Such details may be better addressed in an internal BSEE guidance document, which may be revised as circumstances warrant.

Foam Firefighting Systems (§ 250.861)

Section summary—Final § 250.861 establishes requirements for the use of foam firefighting systems. Under the final rule, when foam firefighting systems are installed as part of a firefighting system, the operator must annually: (1) Conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration; and (2) send tested samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing and certification. The final rule specifies that the certification document must be readily accessible for field inspection. In lieu of sampling and certification, the final rule allows operators to replace the total inventory of foam with suitable new stock. The rule requires that the quantity of concentrate must meet design requirements, and that tanks or containers must be kept full but with additional space allowed for expansion.

Regulatory text changes from the proposed rule—BSEE revised this section in the final rule to clarify that it is applicable to firefighting systems that protect production handling areas. This revision is based upon comments received about jurisdictional concerns.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Limit to Fixed Platforms

Comment—A commenter recommended that this paragraph be limited to fixed platforms only. The commenter asserted that item 12 of the MOA OCS–04 between MMS (now BSEE) and the USCG provides that firefighting safety equipment and systems on floating offshore facilities are the responsibility of the USCG.

Response—BSEE does not agree that the recommended change is necessary. As previously explained, these regulations apply only to those operations, whether on fixed or floating platforms, that are covered by BSEE authority. However, BSEE has revised the final rule to clarify that it applies only to production handling areas, which are subject to BSEE's authority.

Sample Testing

Comment—A commenter stated that proposed paragraphs (a) and (b) would impose new requirements for sending in samples for testing. The commenter asserted that this would require additional costs and resources to comply but would not add significant value. The commenter also stated that other requirements in paragraph (a) would be sufficient to ensure the suitability of the foam.

Response—BSEE does not agree that the testing requirements of this section will not add value. Regular testing of the foam concentrate will ensure that it does not deteriorate and that it will be effective in the event of a fire. If an operator plans for sampling and testing in accordance with this section, that process should not add significant new costs. For example, the sampling can be arranged to coincide with already scheduled trips to and from the facility.

Fire and Gas-Detection Systems (§ 250.862)

Section summary—The contents of existing § 250.803(b)(9) have been revised and moved to § 250.862 in the final rule. This section establishes requirements pertaining to fire and gas-detection systems. Operators must install fire (flame, heat, or smoke) sensors in all enclosed classified areas and must install gas sensors in all inadequately ventilated, enclosed classified areas. All detection systems must be capable of continuous monitoring. A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. This section incorporates several API standards that operators must follow for these systems.

Regulatory text changes from the proposed rule—BSEE revised this section to clarify that it applies only to production processing areas. BSEE also clarified that, to the extent compliance with the identified industry standards would conflict with an applicable USCG regulation, the USCG requirement controls.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Limit to BSEE-Regulated Systems

Comment—A commenter recommended that this paragraph be limited to BSEE regulated safety systems only. The commenter asserted that item 12 of the MOA OCS–04 between MMS (now BSEE) and the USCG provides that fire and smoke detection systems on floating offshore facilities are responsibility of the USCG, except where those detection systems interface with BSEE regulated safety systems.

Response—As previously discussed, these regulations apply only to operations that are under BSEE's authority. Proposed § 250.862, in effect, merely proposed to recodify, with limited alterations, longstanding requirements of BSEE regulation that existed at the time of the MOA cited by the commenter,[24] and the application of which has not presented jurisdictional issues. Nevertheless, BSEE has revised this section of the final rule to clarify that it applies only to production processing areas, which are under BSEE's authority. BSEE also has revised final paragraph (e) to clarify that, in the event compliance with any provision of the standards referenced in this section would conflict with any provision of an applicable USCG regulation, compliance with the USCG regulation controls. BSEE and USCG authority was discussed previously in part IV.B.2.

Applicability

Comment—A commenter suggested revising the requirement for ''gas detection systems'' in proposed § 250.862(e) to ''gas detectors,'' asserting that there is ''type approval'' in place for gas detectors but not for gas detection systems. The commenter also stated that some legacy gas detectors do not have approval because they were manufactured prior to the approval standard issue date, and recommended that BSEE apply the proposed requirement only to new installations. The commenter also asserted that the proposed rule could conflict with USCG requirements for fire and gas detection systems on floating offshore installations.

Response—The relevant provisions in the final rule are consistent with current regulations. The distinction identified by the commenter between ''gas detection systems'' and ''gas detectors'' does not present an issue under these longstanding requirements; nor should the recodification of the existing requirements apply only to new installations. In addition, as previously discussed, these regulations apply only to operations that are under BSEE's authority. Nonetheless, BSEE has revised the final rule to clarify that it applies only to production processing areas and that, in the event compliance with any provision of the standards would be in conflict with any applicable USCG regulation, compliance with the USCG regulation controls.

Electrical Equipment (§ 250.863)

Section summary—The final rule recodifies existing § 250.803(b)(10) as § 250.863, which pertains to basic requirements for electrical equipment and systems. BSEE has revised this provision for clarity and plain language.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Limit to BSEE-Regulated Electrical Systems

Comment—A commenter recommended that this paragraph be limited to BSEE-regulated electrical systems only. The commenter asserted that item 14 of the MOA OCS–04 between MMS (now BSEE) and the USCG provides that electrical systems—other than production, drilling, completion well servicing and workover operations—on floating offshore facilities are the shared responsibility of BSEE and the USCG, except for emergency lighting, power generation and distribution systems, which the commenter stated are the sole responsibility of the USCG.

Response—Final § 250.863, in effect, merely recodifies the longstanding requirements of existing § 250.803(b)(10), which was in effect at the time the MOA referred to by the commenter was developed and the application of which has not presented jurisdictional issues. This final rule is not a substantive change to the existing regulations, and only applies to operations under BSEE's authority. Thus, there is no reason to adopt the commenter's suggested revision.

Erosion (§ 250.864)

Section summary—The final rule moves the contents of existing § 250.803(b)(11), pertaining to erosion control, to new § 250.864.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section in the final rule.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Corrosion Management

Comment—A commenter observed that this section would be clearer if it addressed corrosion monitoring and corrosion control as two separate aspects of a corrosion management program. The commenter recommended that BSEE require that operators implement erosion monitoring programs for wells or fields that have a history of (or could reasonably be expected to encounter) erosion due to sand production. The commenter asserted that, with this revision, not all fields/wells/leases would require an erosion control program.

Response—The proposed rule did not propose any substantive changes to the requirements in the existing regulation. By contrast, the commenter's suggested revision would impose new requirements for corrosion monitoring and control and erosion monitoring that were not part of the proposed rulemaking and are outside the scope of this final rule.

Surface Pumps (§ 250.865)

Section summary—Final § 250.865, pertaining to surface pumps, contains material from existing § 250.803(b)(1)(iii) related to pressure and fired vessels and adds new requirements for pump installations. Final paragraph (a) includes a specific requirement to equip all pump installations with the protective equipment recommended by API RP 14C, Appendix A, section A.7, and final paragraph (b) includes a new requirement to use pressure recording devices to establish new operating pressure ranges for pump discharge sensors when operating pressures change by a specified amount. As noted in the proposed rule, the final rule also adds provisions related to the operation of PSL and PSH sensors, temperature safety element (TSE), and pump pressures.

Regulatory text changes from the proposed rule—In response to comments on similar provisions in other sections of the proposed rule, BSEE revised paragraph (b) of the final rule to clarify the requirements for establishing a new operating pressure range following a change in normalized system pressure. These revisions make final paragraph (b) consistent with similar provisions in other sections of the final rule.

BSEE also added new paragraph (c) in the final rule to improve the presentation and clarity of the information contained in proposed paragraph (b), reformatting that information as a table to be consistent with the structure in other sections related to PSLs and PSHs, and to clarify that initial set points for pressure sensors must be set using gauge readings and engineering design. Final paragraph (c) is consistent with the requirements for operating pressure ranges and pressure sensors in other sections of the final rule.

In light of the other revisions made to the proposed section, the remaining paragraphs of the proposed rule were redesignated as paragraphs (d) through

[24] MOA OCS–04 was revised by BSEE and USCG in January 2016, after the proposed rule was published and comments submitted. The revised MOA is available at *https://www.bsee.gov/sites/bsee.gov/files/memos/internal-guidance/010-2016-moa.pdf.*

(g). BSEE also revised final paragraph (d) to clarify that the PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner. In addition, BSEE revised final paragraph (g) to insert the phrase ''as appropriate for pump type and service'' for additional clarification.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Normalized System Pressure Threshold

Comment—One commenter declared that a pressure change of 50 psig or 5 percent is too low a threshold to require re-running a pressure chart and suggested raising the pressure change threshold 100 psig or 15 percent.

Response—No changes are necessary. As discussed in response to similar comments on other sections, the proposed—and now final—threshold is consistent with similar requirements in other sections of the final rule, and is intended to both reduce the number of nuisance shut-ins and to provide a safety ''cushion'' that will give operators more time to act in the event the pressure change indicates an actual abnormal condition. The commenter's suggestion for a higher threshold, by contrast, would not accomplish those goals, as previously discussed, and could result in higher risk that an incident will occur.

Applicable Pumps

Comment—One commenter noted that it was unclear as to what ''pumps'' the requirement in proposed paragraph (a) would apply. The commenter assumed that this provision would apply only to those pumps in the production process and to pipeline transfer, small volume produced hydrocarbon transfer, or other process fluids transfer pumps recognized in API RP 14C. The commenter recommended that BSEE clarify this requirement to apply only to those pumps specifically recognized in API RP 14C.

Response—No changes are necessary. This section, by its terms, is applicable to the types of surface pumps specified in the section heading and addressed by API RP 14C, which is already incorporated in longstanding BSEE regulations. BSEE is not requiring operators to follow API RP 14C for any surface pumps other than those specified in that standard.

Threshold for Pressure Monitoring

Comment—A commenter claimed that continuous monitoring for a 5 percent pressure change threshold would be problematic and asserted that the proposed regulation would not compensate for lower operating ranges, especially when considering pumps that discharge to pressure vessels that operate at just above atmospheric service. The commenter included an example scenario for a sump pump discharging to a pressure vessel, and discussed the effects the proposed requirement would have under that scenario.

Response—No changes are necessary. As previously stated, the 5 percent pressure change threshold is consistent with the API RP 14C pressure tolerance setting for PSHL sensors. Moreover, the thresholds established by the rule represent pressure changes at which an operator must establish new operating pressure ranges; however, operators may use a more conservative approach, by resetting their operating pressure ranges following a pressure change that is less than 5 percent or 50 psig, to account for situations like that raised by the commenter. If there are additional concerns about the operating range in a specific situation, operators may contact the District Manager for guidance. BSEE also added language to final paragraph (b) to clarify the requirements for establishing the new pressure range.

Comment—According to a commenter, most operators do not monitor the operating ranges to see if they fluctuate by 5 percent because such fluctuations do not typically indicate a change in the maximum operating pressure. The commenter stated that current practices for ensuring pressures are below the maximum operating pressure are sufficient to ensure proper operation, that industry would need to institute new field protocols, which would require additional resources by the operator, to comply with the proposed requirement, and that it is not clear that this new requirement would add value beyond current requirements. The commenter recommended specific revisions to paragraph (b) that would increase the proposed 5 percent pressure change threshold to 15 percent.

Response—No changes are necessary. As discussed in prior responses to similar comments, the thresholds in this section of the proposed and final rule are intended to help prevent nuisance shut-ins as well as safety and environmental incidents, while the commenter's suggested higher thresholds would not satisfy the safety and environmental protection goals of this section and would not help prevent nuisance shut-ins through more frequent re-setting of operating pressure ranges. If an operator has additional concerns about the specified threshold for re-setting the operating pressure range under specific circumstances, the operator can contact the District Manager for guidance or seek approval for an alternate procedure under the DWOP process or existing § 250.141. However, BSEE added language to the final rule (consistent with similar provisions in other sections) that specifies a time interval for recording pressure as a basis for a new operating pressure range. This clarification should help mitigate the commenter's asserted concern about the need for new field protocols.

Comment—A commenter suggested revising the language of proposed § 250.865(b), since the highest operating pressure of the discharge line should include the transient pressure spike associated with starting up or shutting down system pumps, provided that the pressure spike is within the system MAWP; otherwise, the commenter asserted, the PSH sensor will trip whenever an additional pump is started, forcing operations to temporarily bypass the PSH sensor. The commenter stated that it is very difficult to completely design away transient pressure spikes for liquid-filled systems. The commenter also requested that BSEE clarify the proposed requirement for re-establishing operating pressure range when normalized operating pressure changes by 5 percent. The commenter also asserted that proposed § 250.865(b) would only prohibit setting PSH/PSL trip points that are more than 15 percent above/below the established pressure range, so that a 5 percent change in pressure that moves the operating pressure closer to the trip point would not violate this requirement. The commenter suggested that, to avoid conflicts, re-running the range charts should only be required if the change exceeds the parameters of § 250.865(b). The commenter also recommended specific revisions to paragraph (b) to address the commenter's concerns.

Response—No changes are necessary. With regard to the commenter's concern about transient pressure spikes (during start-ups or shutdowns) causing the PSH sensor to trip, BSEE revised final paragraph (b) by adding minimum and maximum time periods (*i.e.,* no less than 4 hours and no more than 30 days) for recording pressures to be used in setting a new operating pressure range. The minimum time period is intended to ensure that the system pressure is stable during the recording period used to set a new operating range. The time period limits were also set, in part, in order to allow operators to discern repeatability, including pressure spikes and/or surges, during the time period. These time period limits should reduce, if not eliminate, the commenter's concern about transient pressure spikes during pump startup and shutdown. In addition, the pressure recording time period limits and other revisions to final paragraph (b), as discussed in prior responses to similar comments, clarify the requirement for recording pressures and resetting the normal operating pressure range, as requested by the commenter.

With regard to the commenter's assertions regarding the proposed PSH/PSL trip points (which BSEE moved from paragraph (b) to paragraph (c) in the final rule), BSEE agrees that this provision does not preclude an operator from setting a PSH or PSL trip point below the specified maximum of 15 percent (or 5 psi, whichever is higher) above the highest operating pressure of the discharge line. Thus, as the commenter observed, a trip point that is 5 percent above the highest operating pressure of the discharge line would not violate this requirement. However, BSEE notes that, as proposed, final paragraph (c) specifies that the trip point for a PSH sensor must be set at least 5 percent (or 5 psi, whichever is greater) below the set pressure of the PSV; not 15 percent below the pressure range, which the commenter incorrectly implied was part of the proposal. The 5 percent limit in this provision is intended to improve safety and environmental protection by assuring that the pressure source is shut-in before the PSV activates; while the 15 percent limit suggested by the commenter would not be as effective in meeting those goals. If an operator has any additional concerns about its operating pressure range, it they can contact the District Manager for guidance.

Maximum Discharge Pressure

Comment—One commenter noted that, under proposed paragraph (f), the pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver. The commenter asserted that the maximum discharge pressure for centrifugal pumps typically is determined by the maximum suction pressure at the shutoff head and, for positive displacement pumps, by the set pressure of the PSV at the discharge.

Response—BSEE agrees with the commenter and has revised final paragraph (g) of this section to clarify the appropriate method to determine the pump maximum discharge pressure, using the maximum possible suction pressure and the maximum power output of the driver as appropriate for the pump type and service.

Personnel Safety Equipment (§ 250.866)

Section summary—Final § 250.866 is a new section that requires the operator to maintain all personnel safety equipment located on a facility in good working condition, without regard to whether the equipment is required.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Move Section to Subpart A

Comment—A commenter asserted that this proposed requirement is out of place in this section of subpart H, stating that it is a general duty statement that belongs in subpart A at § 250.107. The commenter recommended deleting this requirement from subpart H.

Response—BSEE does not agree that it would be appropriate to move this provision to subpart A at this time. BSEE agrees with the commenter that this requirement might be an appropriate addition to subpart A at a future date through a separate rulemaking. Moving this section to subpart A in this final rule, however, would be outside the scope of this rulemaking. Nor is it inappropriate to include this requirement in subpart H, since it is certainly applicable to personnel safety equipment located on facilities subject to this final rule.

BSEE Responsibilities

Comment—Several comments requested clarification on BSEE's responsibilities for personnel safety equipment requirements on the OCS compared to USCG's responsibilities. The commenters expressed their opinion that USCG, not BSEE, should have oversight for required and non-required personnel safety equipment on the OCS. They recommended that BSEE remove this requirement from subpart H.

Response—BSEE is not requiring any new additional personnel safety equipment under this provision, but only requiring that this equipment, if located on a facility, be maintained in good working condition. As previously discussed, this final regulation applies to operations and systems, including safety issues, on facilities under BSEE's jurisdiction.

Temporary Quarters and Temporary Equipment (§ 250.867)

Section summary—Final § 250.867 is a new section that requires that all temporary quarters to be installed in production processing areas or other classified areas on OCS facilities be approved by BSEE and be equipped with all safety devices required by API RP 14C, Appendix C. It also clarifies that the District Manager may require the installation of a temporary firewater system. This new section also requires that temporary equipment in production processing areas or other classified areas used for well testing and/or well clean-up be approved by the District Manager. These temporary equipment requirements are based on a number of incidents involving the unsuccessful use of such equipment and will help ensure that BSEE has a more complete understanding of all operations associated with such temporary quarters and temporary equipment.

Regulatory text changes from the proposed rule—BSEE revised paragraph (a) of this section in the final rule to state that the District Manager must approve the installation of all temporary quarters installed in production processing areas or other classified areas on OCS facilities. BSEE also revised paragraph (b) to clarify that the District Manager may require temporary firewater systems ''for'' (rather than ''in'') temporary quarters in such areas, and revised final paragraph (c) to clarify that the District Manager must approve temporary equipment associated with the production processing system, including equipment used for well testing and/or well clean up. These changes were made to clarify that these requirements apply to areas or equipment under BSEE's authority.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

BSEE Authority

Comment—A commenter asserted that the proposed rule exceeded BSEE's authority as fire-fighting requirements for accommodations and machinery spaces are the responsibility of the USCG. Additionally, the commenter stated that there are no BSEE requirements in either the existing regulations or the proposed regulations that require firewater systems in permanent quarters or temporary quarters. The commenter recommended that BSEE delete this section from the proposed rule.

Response—As previously discussed, these regulations apply only to operations under BSEE's authority. These requirements are based on several past incidents involving unsuccessful use of temporary equipment. Currently, BSEE receives limited information regarding temporary equipment. This final rule will help ensure that BSEE has a more complete understanding of operations associated with temporary quarters and temporary equipment in production processing or other classified areas, which in turn will help BSEE ensure that such operations are conducted in a manner that prevents or minimizes the likelihood of fires and other incidents that may damage property or the environment or endanger life or health.

In addition, BSEE expects operators to address the impacts of the temporary quarters and temporary equipment in their SEMS plans. This could include, for example, conducting a hazards analysis (*see* § 250.1911) for the installation of temporary quarters or evaluating safe work practices (*see* § 250.1914) for temporary equipment.

Non-Metallic Piping (§ 250.868)

Section summary—Section 250.868 is a new section that was proposed to limit the use of non-metallic piping to atmospheric, primarily non-hydrocarbon service (such as open atmospheric drains) and thereby preclude the use of non-metallic piping in other situations, such as production process piping (*i.e.,* piping that handles produced hydrocarbons).

Regulatory text changes from the proposed rule—In response to comments, BSEE revised this section to clarify that it applies only to non-metallic piping on fixed OCS facilities and to refer to the requirements for piping in final § 250.841(b), which incorporates API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems. Section 250.841(b) specifically addresses the installation, repair, testing, and maintenance of production process piping, while API RP 14E includes comprehensive provisions for surface piping systems, including non-metallic piping.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Non-Metallic Piping

Comment—A commenter suggested that this section should be revised to prohibit non-metallic piping for hydrocarbons. The commenter asserted that firefighting piping can be made out of fiberglass reinforced plastic, provided that it does not penetrate a bulkhead and is always wet inside. The commenter asserted that polyvinyl chloride firefighting piping is not good practice and should never be allowed. The commenter also stated that non-metallic piping should not be allowed to penetrate bulkheads or decks, even if atmospheric. The commenter also suggested that BSEE's rules for non-metallic piping should take into consideration the USCG's rules.

Response—BSEE agrees that the proposed section did not fully address all situations in which use of non-metallic piping would or would not be allowed, and that there could be potential confusion about the proposed rule's relation to USCG regulations. Accordingly, BSEE revised this section in the final rule to require that the use of non-metallic piping on fixed facilities be in accordance with the requirements of § 250.841(b), which specifically addresses platform production process piping and which incorporates API RP 14E, including provisions for non-metallic piping. This revision will provide greater clarity to operators while achieving the original purpose of the proposed rule.

Jurisdiction

Comment—A commenter recommended that BSEE limit the proposed requirement in accordance with MOA OCS–04 between MMS (now BSEE) and the USCG. The commenter asserted that piping in galleys and living quarters, as well as firewater systems piping, on floating offshore facilities is the responsibility of the USCG. The commenter added that USCG has specific requirements for the use of non-metallic piping in USCG-regulated systems on such facilities.

Response—As stated in prior responses, BSEE's regulations apply only to operations and systems that are under BSEE authority. However, to further clarify this point, BSEE has revised this section to specify that it only applies on fixed OCS facilities, and to refer back to § 250.841(b), which specifically addresses production process piping and which also incorporates API RP 14E's provisions for non-metallic piping. These revisions limit the scope and applicability of final § 250.868 so as to avoid concerns about its consistency with MOA OCS–04 (as updated on January 28, 2016).

Atmospheric and Pressurized Piping

Comment—One commenter asserted that the proposed regulatory text is confusing in its use of the term ''atmospheric,'' in that the examples given in the proposal implied pressurized piping greater than atmospheric pressure. The commenter said that typical freshwater piping in galleys and living quarters operates at ±75 psig and firewater systems piping operates at ±200 psig.

Response—BSEE agrees with the commenter that the piping in galleys and living quarters and firewater system piping is pressurized piping. BSEE has revised this section in the final rule and eliminated the proposed references to piping in galleys and living quarters and in firewater systems, thus eliminating the potential confusion noted by the commenter. Instead, the final rule now refers to the more comprehensive requirements of § 250.841(b).

New Technology

Comment—A commenter suggested revising the language of proposed § 250.868, since it would cover new technology such as non-metallic HPHT pipe (*e.g.,* Magma's M-pipe) and would preclude the use of M-pipe for future weight-saving in areas such as topside water injection (WI) piping and subsea jumpers. The commenter also suggested that the requirement should be clarified so that it only applies to new installations and does not implicitly require removal of existing approved installations.

Response—As previously stated, BSEE revised this section in the final rule to limit it to fixed OCS facilities and to cross-reference the requirements of final § 250.841(b). Topside WI piping is only found on floating facilities, which are outside the scope of this final provision. The design of subsea jumpers is covered in subpart J of BSEE's regulations and is likewise not within the scope of this section.

General Platform Operations (§ 250.869)

Section summary—BSEE has moved the contents of existing § 250.803(c), pertaining to general platform operations, to final § 250.869, and revised the language for improved clarity. The final rule also includes, as proposed, a new requirement (§ 250.869(e)) that prohibits use, on new installations, of the same sensing points for process control devices and component safety devices.

In addition, as proposed, final paragraph (a) requires that a designated visual indicator be used to identify a bypassed safety device and establishes required monitoring procedures for bypassed safety systems. Final paragraph (a)(1) also sets forth the monitoring requirements for non-computer-based safety systems, while paragraph (a)(2) sets forth the monitoring requirements for computer-based technology systems. More specifically, final paragraph (a)(2)(i) requires computer-based technology system control stations to show the status of operating conditions and to be capable of displaying those conditions, provided that if the computer-based system is not capable of displaying operating conditions, the operator must use field personnel to monitor the level and pressure gauges.

In addition, final paragraph (a)(3) specifies that operators must not bypass, for startup, any element of the emergency support system (ESS) or other support system required by Appendix C of API RP 14C without first receiving approval from BSEE for a departure.

Regulatory text changes from the proposed rule—BSEE revised the proposed rule by adding a new paragraph (f) to clarify that control panels and control stations must be marked consistently with each other using consistent nomenclature as provided in API RP 14C.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Pressure and Temperature-Take Points

Comment—A commenter requested that BSEE revise this section to clarify whether it would require additional pressure and temperature-take points on subsea trees and other subsea equipment. The commenter asserted that it is usually desirable to minimize these leak paths.

Response—No changes are necessary. This regulation does not introduce additional leak paths; it only separates process controls from safety controls in order to ensure the sensing line is only performing a single function. If the process controls and safety controls were not separate, a problem with one system could result in a problem with both systems, thus creating a greater risk that a failure in a process control would also cause a safety system malfunction. Requiring separate systems is also consistent with API RP 14C, which states that the safety system should provide 2 levels of protection, independent of and in addition to the control devices.

Time Delays on Pressure Safety Low (PSL) Sensors (§ 250.870)

Section summary—Final § 250.870, related to time delays on PSL sensors, is a new provision that codifies guidance from NTL No. 2009–G36. The final rule specifies that operators may apply any or all of industry standard Class B, Class C, or Class B/C logic to all applicable PSL sensors installed on process equipment, as long as the time delay does not exceed 45 seconds. It also requires that operators document on their field test records any use of a PSL sensor with a time delay greater than 45 seconds. Final § 250.870 also describes how PSL sensors fit under Class B, Class C, or Class B/C.

The final rule also provides that if an operator does not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, the operator must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds.

Regulatory text changes from the proposed rule—Throughout this section, the word ‘‘BSEE’’ was removed before the ‘‘District Manager’’ for consistency with other sections and because it was unnecessary. In response to comments, BSEE revised final paragraph (a) to state that the operator ‘‘may apply’’ industry standard class logic to applicable PSL sensors, rather than stating that the operator ‘‘must apply’’ such logic, as proposed. Similarly, BSEE replaced the phrase ‘‘apply any or all of the industry standard Class B, Class C and Class B/C logic’’ with ‘‘apply industry standard Class B, Class C or Class B/C logic’’ in order to clarify that the operator may choose to use any one (or more) of those classes rather than all three of the classes. In addition, BSEE removed proposed references to alternate procedures under § 250.141 from the final rule because § 250.141 is potentially applicable to all requirements under part 250 and does not need to be expressly cited in this section.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

BSEE Role

Comment—One commenter stated that BSEE should not be involved in these day-to-day operational decisions regarding pressure safety devices, as proposed in this section.

Response—Appropriate use of pressure safety devices is critical to ensuring safety and protection of the environment. However, BSEE revised this section in the final rule to state that the operator may apply the class logic, but is not required to use it. This revision gives the operator greater flexibility in meeting this safety goal by allowing for time delays, instead of requiring the operator to bypass the PSL sensors.

Bypasses

Comment—A commenter recommended that PSL sensors should not be required to have timed or pressure build-up bypasses for startup activities. The commenter also asserted that the proposed rule implied that all three industry standard Class logics must be applied simultaneously. Therefore, the commenter recommended that the first sentence be reworded as follows: ‘‘You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment. . . .’’ The commenter also asserted that the proposed time limit of 45 seconds for delaying the PSL sensor bypass could be unreasonable during a startup scenario and could cause startup operations to be rushed unnecessarily. The commenter recommended that the time delay be extended to several minutes to account for this.

Response—BSEE agrees with the commenter regarding the proposed class logic language and revised paragraph (a) of this section to state that the operator may apply any or all of the Class B, C or B/C logic, but is not required to use any of those choices. This gives the operator flexibility by allowing for time delays, instead of requiring the operator to bypass the PSL sensors. If BSEE had required the operator to apply class logic, some existing facilities would need to be retrofitted. This revision is consistent with the intent of the proposed rule, which provided in paragraph (b) that an operator that does not use a class logic approach must manually bypass the PSL sensor.

However, BSEE disagrees with the suggestion for extending the time limit on delays to several minutes. Based on BSEE's experience, and consistent with NTLNo. 2009–G36, 45 seconds is typically a reasonable period for pressure to fluctuate before it becomes necessary to alert the operator to an abnormal condition that must be addressed. By contrast, allowing the pressure to remain low for several minutes before the sensor alerts the operator could significantly increase the potential safety risk from the abnormal condition. Thus, BSEE must approve any request to extend the delay period beyond 45 seconds in a specific case.

Welding and Burning Practices and Procedures (§ 250.871)

Section summary—BSEE moved the content of existing § 250.803(d), pertaining to welding and burning practices and procedures, to final § 250.871. BSEE revised the existing language for clarity and plain language and updated the regulatory cross-references.

Regulatory text changes from the proposed rule—BSEE did not make any significant changes to this section. BSEE deleted the proposed cross-reference to the alternate procedures approval process under § 250.141 since that provision is applicable to all requirements in part 250 and does not need to be expressly referenced.

Comments and responses—BSEE received one comment on this section and responds to that comment as follows:

Alternate Compliance and Departures (Variances)

Comment—The commenter asserted that operators should be required to obtain BSEE approval for any variance from a regulatory requirement, including industry standards incorporated by reference into the regulations, and from any approval, permit, or authorization issued by BSEE for an OCS oil and gas production facility.

Response—These types of requests are already covered by existing §§ 250.141 and 250.142 in the form of alternate compliance and departure requests, respectively; therefore, no revision to the regulation is needed in response to this comment.

Atmospheric Vessels (§ 250.872)

Section summary—Final § 250.872 is a new section that requires atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids, as described in API RP 500 or 505, to be equipped with protective equipment identified in API RP 14C. It also includes requirements for level safety high (LSH) sensors) and clarifies that, for atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket. In addition, paragraph (c) requires that all flame arrestors be maintained to ensure proper design function.

Regulatory text changes from the proposed rule—BSEE revised proposed paragraph (a) to list types of tanks that are not required to be equipped with protective equipment.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Authority

Comment—A commenter recommended that BSEE revise this section to state that it is not applicable to the design or operation of tanks inside the hull of a floating facility. The commenter asserted that USCG requirements may be different from BSEE requirements for tanks inside the hull of a unit. Alternatively, the commenter suggested that BSEE–USCG MOA OCS–04 should be revised to give USCG jurisdiction over the design of any tanks that are integral to the hull and to give BSEE jurisdiction over any non-integral tanks in the hull of the unit and over the operation of both integral and non-integral tanks in the hull of the unit that are for produced hydrocarbons, fuel and flow assurance fluids.

Response—BSEE disagrees. This section relates to atmospheric vessels that are a component of drilling, completion, well servicing, and workover operations and that are under BSEE jurisdiction. BSEE is not regulating the design or operation of the tanks; rather, this regulation only requires sensors to ensure safety in the operations BSEE oversees. This is consistent with MOA OCS–04, which was updated in January 2016, and which applies only to floating facilities.

Non-Permanent Storage

Comment—A commenter asked whether it was BSEE's intent to include non-permanent storage of chemicals and other substances used for ancillary operations such as well work, painting, etc. The commenter asserted that, if that was BSEE's intent, compliance would be difficult since many products are stored in transporters, drums and buckets. The commenter stated that inclusion of devices such as LSH sensors would serve no useful purpose since they would not have a ''source'' to shut in, and connecting them to facility safety systems would impose a major burden since they are moved frequently. The commenter asserted that the proposed requirements for venting and/or flame arrestors for drums and transporters are understandable, but requiring full compliance with API RP 14C atmospheric vessel requirements would impose additional burdens that provide no tangible benefits. The commenter provided recommended revisions to the proposed language.

Response—BSEE does not intend to include non-permanent storage of chemicals and other substances used for ancillary operations such as well work, painting, etc., within the scope of this requirement. The relevant tanks are sealed, with no venting or inlet-outlet valves, and they are not connected to the production process train. To clarify this point, BSEE revised this section to exclude U.S. Department of Transportation-approved transport tanks that are sealed and not connected via interconnected piping to the production process train and that are used for storage only of refined liquid hydrocarbons or Class I liquids.

However, BSEE does not agree with the suggestion for requiring the TSE on atmospheric tanks that are not connected via interconnected piping to the production process train because these tanks are sealed, *i.e.,* there is no venting and no inlets or outlets. BSEE does agree that the TSE is needed if the tank is connected to the production process chain for fire protection.

Comment—A commenter asserted that proposed paragraph (b) would have a huge impact for manufactured ''standard'' designs currently in service that do not have nozzles for moving level sensors. The commenter asserted that placing LSH sensors in oil buckets may not necessarily reduce risk of pollution, depending on individual equipment design. The commenter added that many systems are configured for the oil bucket level to be much lower than the main compartment level (to prevent overflow of the oil into water) so an LSH sensor in an oil bucket would not sense true ''high'' levels in the component, requiring two LSH sensors to be installed rather than just relocating the LSH sensor. The commenter claimed that it would be difficult to retrofit vessel oil buckets with an LSH sensor if they do not have the appropriate nozzles and asked whether exceptions would be made for existing equipment currently in service. The commenter provided recommended language to address its concerns.

Response—BSEE agrees with the commenter that the operator must ensure that all atmospheric vessels, whether existing or new, are designed and maintained to ensure the proper working conditions for LSH sensors. Specifically, to ensure proper working conditions for the LSH sensor, the LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. Similarly, for atmospheric vessels that have oil buckets, proper working conditions means the LSH sensor must be installed to sense the level in the oil bucket. This requirement is not just to protect against overflow but also to prevent oily-water interface from going out the water outlet, thus protecting safety and the environment. Thus, for those reasons, BSEE does not agree with the commenter's suggestion to limit the requirements for atmospheric vessels with oil buckets only to new equipment (*i.e.,* that comes into service after this rule takes effect). BSEE expects that most existing equipment will already be in compliance with this requirement, and for those that are not, compliance would only require the relocation of the LSH sensor. However, if an operator requests approval of alternate equipment or a departure from this requirement for the equipment currently in service, BSEE will consider such requests on a case-by-case basis.

Subsea Gas Lift Requirements (§ 250.873)

Section summary—This is a new section that codifies existing policy and guidance from the DWOP process. Under DWOPs, BSEE has approved the use of gas lift equipment and methodology in subsea wells, pipelines, and risers and has imposed conditions to ensure that the necessary safety mitigation measures are in place. While the basic requirements of API RP 14C will apply for surface applications, certain clarifications are made in this section to ensure regulatory compliance when gas lift for recovery for subsea production operations is used. Specifically, final § 250.873 requires that: Gas lift supply pipelines be designed according to API RP 14C; installation of specified safety valves, including a gas-lift shutdown valve and a gas-lift isolation valve, be tailored to operational circumstances; valve closure times and hydraulic bleed time requirements be in accordance with the approved DWOP; and gas lift valve systems be periodically tested to ensure that they do not exceed specified allowable leakage rates.

Regulatory text changes from the proposed rule—The table in proposed paragraph (b) was revised in the final rule to reflect comments received and to be consistent with the guidance of NTL No. 2009 G–36. BSEE also deleted an extraneous phrase that was inadvertently included in proposed paragraph (b)(1)(i).

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Consistency With NTL No. 2011–N11

Comment—A commenter asserted that the tables in proposed §§ 250.873, 250.874 and 250.875 are inconsistent with the tables issued in NTLs, guidance provided via DWOP approvals, and discussions with BSEE GOM Region's Technical Assessment Section. The commenter recommended that BSEE revisit and revise the tables according to NTL No. 2011–N11 and previous guidance issued to operators as part of the DWOP process.

Response—BSEE agrees with the commenter and has revised the tables to be more consistent with the referenced NTL and BSEE guidance provided to operators during the DWOP process. However, not every detail relevant to subsea gas lift systems can be included in the final rule. There are three different gas lift situations, each using a different system, and the nuances for these systems are better addressed in guidance. BSEE plans to revise the referenced NTL to address those details that are not covered in this final rule.

Gas Lift System

Comment—A commenter requested that, for clarity, the word ''system'' should be added after ''gas lift'' in the first sentence of paragraph (d). The commenter asked why there was no allowable leakage rate specified for the valve in proposed paragraph (d)(1), given that a gas lift isolation valve (GLIV) is required when gas lifting a subsea pipeline, pipeline riser, or manifold via an external gas lift pipeline, as described in proposed paragraph (b)(1).

Response—BSEE agrees with the commenter's suggestions for revising paragraph (d) by adding the word ''system'' after ''gas lift'' in the first sentence. No other changes are necessary, however. Under paragraph (b)(1), the GLIV must be installed downstream of the USV(s) and/or AIV(s). The GLIV prevents flow back to the facility. For gas lift of a subsea pipeline, pipeline riser, or manifold via an external gas lift pipeline, the USV is the primary barrier and is leak tested; the GLIV is not the primary barrier, so a leak test is not required.

Subsea Water Injection Systems (§ 250.874)

Section summary—This is a new section that codifies existing policy and guidance from the DWOP process, related to water flood injection via subsea wellheads. This is similar to the subsea gas lift situation discussed in the previous section. The basic requirements of API RP 14C apply for water flooding from the surface, but BSEE made some clarifications in this section regarding the use of water flood systems for recovery in subsea production operations. Final § 250.874 requires operators to meet the following requirements: Adhere to the WI provisions in API RP 14C for the WI equipment located on the platform; equip the WI system with certain safety valves, including water injection valve (WIV) and a water injection shutdown valve (WISDV); establish valve closure times and hydraulic bleed requirements according to the approved DWOP; and conduct WIV testing in accordance with the rule.

Regulatory text changes from the proposed rule—BSEE revised the introductory paragraph to clarify that the regulations are the minimum requirements for the subsea WI system, that the operator's DWOP must address the applicable requirements, and that the operator must comply with the approved DWOP. BSEE also restructured the section, creating shorter, easier to follow paragraphs.

BSEE revised final paragraph (g) to clarify the testing requirements. In particular, BSEE revised proposed paragraph (g)(2) to address the actions that an operator must take if a designated USV on a WI well fails its test. BSEE retained in the final paragraph the proposed requirement that the operator must designate another certified subsea valve as a USV, in place of the USV that failed its test. However, BSEE added language to clarify that this designation requires District Manager approval. In addition, BSEE removed language from proposed paragraph (g)(2) that would have given the operator the option, in lieu of designating a new certified subsea valve as a USV, to modify the valve closure time of the surface-controlled SSSV or WIV after sensor activation. That situation has never occurred in BSEE's experience; thus, that option is not needed in this regulation.

In consideration of a comment received, the final rule omits language from proposed paragraph (g)(3) that addressed function testing the WISDV in cases where the operator had BSEE's approval not to leak test the WISDV. BSEE has decided that the function testing requirements for WISDVs in such circumstances would be more effectively addressed through other means, such as through a departure approval under § 250.142.

In final paragraph (h)(2), BSEE removed the proposed language stating that the District Manager may order a shut-in when there is a loss of communication during WI operations. The deleted sentences were intended only for informative purposes, not as a regulatory requirement, and thus are not needed in the regulation.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Zero-Leak Criteria

Comment—A commenter asked whether the proposed regulations apply to all WI wells and all WI systems. The commenter asserted that these are 'departing pipelines' from the platform, and that the proposed requirement would be inconsistent with API RP 14C.

The commenter also asserted that some WI wells are not connected directly to the reservoir and will not flow back under hydrostatic pressure or would take many years to do so. The commenter, therefore, questioned whether a 'zero-leak' criterion for these wells would be appropriate. The commenter also asserted that the proposed regulations imply that the consequence of any fluid by-pass is similar or identical to that of a hydrocarbon production system and well, while in many instances the bypasses of WI fluids have neither safety nor environmental consequences. Thus, the commenter questioned whether this same valve leakage criterion should apply.

Response—BSEE disagrees with the commenter, and has determined that no changes are necessary based on this comment. These provisions apply to all WI wells and WI systems. Consistent with existing BSEE policy and guidance previously provided to the operators through the DWOP process, the zero-leak rate for these wells is appropriate, and if the well is capable of natural flow to the surface, then the operator needs to test these valves. Any operator that has concerns with its specific subsea WI system should contact the appropriate District Manager, who will review the concerns on a case-by-case basis.

WIV Testing

Comment—A commenter asserted that, because a WIV is defined in § 250.874(a) as a ''water injection valve,'' and because this definition does not include WISDVs (as defined in § 250.874(b)), the acronym ''WIV'' as used in proposed paragraphs (g) and (g)(1) should be replaced with the words ''water injection system valve.'' The commenter also suggested, for clarity, that BSEE add the word ''leak'' to the first sentence of paragraph (g)(3). The commenter questioned whether the requirement that USVs meet the allowable leakage criteria (in the event that the WISDV cannot be tested because the shut-in tubing pressure of the water injection well is less than the external hydrostatic pressure) means that the USVs are to be tested in the direction of the water injection flow. If that is so, the commenter questioned why the WISDV cannot be tested similarly, *i.e.,* in the direction of the flow. The commenter also suggested that BSEE consider the applicability of the proposed requirements and regulations to subsea water injection systems that do not have positive well flowback capability and whether the proposed production valve leakage criteria are necessary for all WI wells and systems.

Response—BSEE agrees with the comment that the acronym ''WIV'' is not appropriate for use in paragraph (g), as proposed, and has replaced the acronym with ''injection valve'' in the introductory sentence of paragraph (g) and in subparagraph (g)(1) of the final rule. In addition, based on the commenter's questions and concerns related to the requirement in proposed paragraph (g)(3) for testing a USV in the event that a WISDV cannot be tested, BSEE has decided that there are a number of technical issues related to such testing that require further consideration by BSEE and that potentially would be better addressed through guidance rather than by regulations at this time. Accordingly, BSEE has removed the relevant language in proposed paragraph (g)(3) from the final rule. BSEE may issue additional guidance on WISDV testing at a later date.

Subsea Pump Systems (§ 250.875)

Section summary—This new section codifies policy and guidance from existing NTL No. 2011–N11, ''Subsea Pumping for Production Operations,'' and the DWOP process. Final § 250.875 outlines subsea pump system requirements, including: The installation and location of specific safety valves and sensors, operational considerations under circumstances where the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the maximum allowable operating pressure (MAOP) of the pipeline, valve closure times and hydraulic bleed times, and subsea pump testing.

Regulatory text changes from the proposed rule—BSEE revised this section to clarify that the operator must ensure that the subsea pump system complies with the approved DWOP, and that the requirements in this section are the minimum requirements for the subsea pump system. BSEE revised the wording in several places to clarify the requirements; however BSEE did not make any substantive changes to the requirements in this section.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Previous Guidance

Comment—A commenter asserted that the tables in the proposed rule are different from previous guidance provided through DWOPs by BSEE GOM Region's Technical Assistance section or NTL No. 2011–N11 (''Subsea Pumping for Producing Operations—Considerations for Using Subsea Gas Lift and Water Flood as Secondary Recovery Methods for Production Operations).'' The commenter recommended revising the rule to align with previous guidance issued to operators. The commenter also noted that the proposed rule does not provide the valve closure timing table included as Table 1 in NTL No. 2011–N11 and recommended including the table in the regulation to avoid confusion during the DWOP approval process. The commenter asserted that the ''loss of communications'' case is addressed in NTL No. 2011–N11, but that the proposed rule did not provide details of how and when to execute an immediate shutdown of a well or subsea boost system. Thus, the commenter requested clarification regarding the shutdown sequence and timing. The commenter also recommended that the tables in the proposed rule be revised to align better with the tables published in the current NTLs.

Response—No changes to this section are necessary in response to these comments. Table 1 from NTL No. 2011–N11, referred to in the comment, is associated with the approval of a specific DWOP. However, the issues associated with that table and these systems are complex, with too many nuances to effectively address in this regulation. Those issues are better addressed through the DWOP process on a case-by-case basis, especially since production systems are site-specific and currently there is no industry standard on subsea pumping. Similarly, under paragraph (d), operators must follow the valve closure times and hydraulic bleed requirements established by their approved DWOPs. Accordingly, BSEE reviews each subsea pumping system individually through the DWOP process. BSEE will review NTL No. 2011–N11 and expects to publish a new NTL consistent with this final rule after the effective date of the final rule.

Subsea Pump Testing

Comment—One commenter indicated that the proposed requirement potentially could be too broad. The commenter acknowledged that certain intervention activities or changes to software and equipment may justify a complete subsea pump function test—including shutdown, but that other, less significant changes might not warrant such a test. The commenter recommended adding the word ''significant'' to proposed paragraph (e)(1) so that it reads: ''Performing a complete subsea pump function test, including full shutdown after any significant intervention, or changes to the software and equipment affecting the subsea pump; and . . .''

Response—BSEE believes that the requirements set forth in paragraph (e)(1) are appropriate and not overbroad under the circumstances; therefore, no changes are necessary at this time. This section deals with newer technology that is still uncommon, and there are currently no well-established industry standards that address how and when function testing of subsea pumps should be conducted. Thus, at present, it is appropriate to require a function test of the subsea pump after any change to software or equipment affecting the subsea pump, whether or not the operator considers the change to be ''significant,'' in order to ensure that the pump will still function as planned after the change. As BSEE and the industry gain experience under this new requirement, BSEE may consider developing further guidance on when function testing is required under this provision.

Fired and Exhaust Heated Components (§ 250.876)

Section summary—This new section requires certain tube-type heaters to be removed and inspected, and repaired or replaced as necessary, every 5 years by a qualified third-party. This section also requires that the operator document the inspection results, retain them for at least 5 years, and make them available to BSEE upon request. This new section was added, in part, due to the BSEE investigation report into the *Vermillion 380* platform fire of September 2010,[25] which determined that ''the immediate cause of the fire was that the heater-treater's weakened fire tube became malleable and collapsed, creating openings through which hydrocarbons escaped, came into contact with a hot burner, and then produced flames.'' The report also stated that a possible contributing cause of the fire was a lack of routine inspections of the fire tube. Since 2011, there have been other similar incidents involving tube-type heaters resulting in potential safety issues for offshore personnel and infrastructure. This new requirement will ensure tube-type heaters are inspected routinely to minimize the risk of tube-type heater incidents.

Regulatory text changes from the proposed rule—In response to comments, BSEE revised the first sentence of this section to clarify that an operator must have the fire tube for tube-type heaters inspected within 2 years after the date of publication of this final rule, and at least once every 5 years thereafter, and then repaired or replaced as needed.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Timing of Initial Inspections

Comment—A commenter asked whether the ''every 5 years'' clock begins the day the proposed regulation is amended or whether the regulation would be retroactive and cause equipment that has not been inspected within the last 5 years to be pulled and inspected.

Response—BSEE revised this section to require the initial inspection within 2 years after the publication of the final rule. The requirement for third-party inspections every 5 years begins to run at the time the initial inspection is completed. This provision is not retroactive.

Safety, Costs, and Benefits for Fire Tube for Inspection

Comment—BSEE received comments that expressed concern about the safety, costs, and benefits related to removing the fire tube for inspection. Commenters indicated that removing the fire tube for inspection requires removing the components and may require a crane, which the commenters asserted would be a potential safety hazard, as well as very costly, and would not add material value to the inspection process. The commenters suggested that BSEE consider alternatives to removing the tube, such as a visual inspection with the tube in place and an option of removing the tube at the qualified third-party inspector's discretion. They recommended that the fired components be inspected at the same interval as their host equipment. They also stated that expected costs of compliance may exceed BSEE's initial projections, since removing the fire tube may require additional equipment and staff and lead to lost production.

Response—No changes to the regulatory text are necessary. These new requirements are based, in part upon BSEE's investigation of the *Vermillion 380* heater-treater ''fire tube'' incident and a related Safety Alert issued after the investigation.[26]

BSEE's investigation into the *Vermillion 380* platform fire of September 2010 determined that the immediate cause of the fire was that the heater-treater's weakened fire tube became malleable and collapsed, creating openings through which hydrocarbons escaped, came into contact with a hot burner, and then produced flames. The report also stated that a possible contributing cause of the fire was a lack of routine inspections of the fire tube. Since 2011, there have been other similar incidents involving tube-type heaters resulting in potential safety issues for offshore personnel and infrastructure. This new requirement will ensure tube-type heaters are inspected routinely to minimize the risk of such tube-type heater incidents. BSEE does not believe that the alternatives suggested by the commenter, such as to removing the tube or inspecting on the same interval as host equipment, would accomplish the purposes of this provision.

BSEE agrees, however, that the costs associated with the inspection of fired and exhaust-heated components may be higher than the initial economic analysis estimated and has adjusted those costs in the final economic impact analysis, as discussed in part V of this document. After considering those costs, however, BSEE has concluded that the balance of relevant safety considerations, and other costs and benefits, justify promulgating this final rule.

Production Safety System Testing (§ 250.880)

Section summary—BSEE moved the contents of existing § 250.804(a), pertaining to production safety system testing, to final § 250.880, and revised those provisions for clarity and plain language. BSEE also added several tables to this section to further clarify its requirements.

Final § 250.880(a) includes the notification requirements from existing § 250.804(a)(12) and requires the operator to notify the District Manager at least 72 hours prior to commencing production so that BSEE may conduct a preproduction inspection of the integrated safety system. The final rule retains the existing requirement to notify the District Manager upon actual commencement of production, and adds a new requirement to notify the District Manager and receive approval before certain types of subsea intervention.

The final rule also retains existing testing and inspection requirements,

[25] BSEE's investigation report, ''*Vermillion* Block, Production Platform A: An Investigation of the September 2, 2010 Incident in the Gulf of Mexico, May 23, 2011,'' is available at *https://www.bsee.gov/sites/bsee.gov/files/vermilion-investigation.pdf*.

[26] Safety Alert 009 (May 25, 2011) summarized the results of the *Vermillion 380* investigation and recommended, among other things, that operators evaluate, and where necessary, update or develop their inspection plans for heater-treaters and regularly inspect heater-treaters. The Safety Alert is available at *http://www.bsee.gov/Regulations-and-Guidance/Safety-Alerts/009-Safety-Alert/*.

with certain alterations. The final rule also adjusts the existing requirements by increasing certain liquid leakage rates from 200 cubic centimeters per minute to 400 cubic centimeters per minute and increasing gas leakage rates from 5 cubic feet per minute to 15 cubic feet per minute. These changes are consistent with industry standards and account for accessibility of equipment in deepwater/subsea applications. In 1999, the former MMS funded the Technology Assessment and Research Project #272, ''Allowable Leakage Rates and Reliability of Safety and Pollution Prevention Equipment,'' to review increased leakage rates for safety and pollution prevention equipment. One of the recommendations from this study by the Southwest Research Institute (SWRI) states that: ''There appears to be preliminary evidence indicating that more stringent leakage requirements specified in part 250 may not significantly increase the level of safety when compared to the leakage rates recommended by API. However, a complete hazards analysis should be conducted, and industry safety experts should be consulted.'' (*See* n. 20, *supra.*) In the past, BSEE has allowed a higher leakage rate than that prescribed in existing § 250.804 as an approved alternate compliance measure in the DWOP because of BSEE's and industry's acceptance of the ''barrier concept,'' which moves the SSV from the well to the BSDV, and which has been proven to be as safe as or safer than what was required by the existing regulations.

The following table compares existing allowable leakage rates to the final increased allowable leakage rates for various safety devices:

Item name	Allowable leakage rate testing requirements under existing regulations	The increased allowable leakage rate testing requirements under the final rule
Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
Tubing plug.	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
Injection valves.	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
USVs.	0 leakage rate.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.
Flow safety valves (FSV).	liquid leakage rate < 200 cubic centimeters per minute, or gas leakage rate < 5 cubic feet per minute.	liquid leakage rate < 400 cubic centimeters per minute, or gas leakage rate < 15 cubic feet per minute.

Additionally, final § 250.880 contains new requirements for BSDVs, changes the testing frequency for underwater safety valves, and adds requirements for the testing of ESD systems, flame, spark, and detonation arrestors, as well as pneumatic/electronic switch LSH and level safety low (LSL) controls. This final section also adds testing and repair/replacement requirements for subsurface safety devices and associated systems on subsea trees and for subsea wells shut-in and disconnected from monitoring capability for greater than 6 months.

Regulatory text changes from the proposed rule—BSEE revised paragraph (a)(1) to clarify that notification to BSEE is required before production begins so that BSEE can conduct a preproduction inspection. BSEE revised the proposed requirements in the tables under paragraph (c) to express the allowable leakage rates in ''standard cubic feet per minute'' instead of ''cubic feet per minute.'' This is consistent with industry practice and with API RP 14B, which is referenced in paragraph (c). BSEE also revised several sentences in paragraph (c) for clarity and to provide consistency in the language regarding timing of the tests. In addition, BSEE revised paragraph (c)(2)(i) to clarify that the main valve piston must be lifted during the required test.

Paragraph (c)(2)(iv) was revised to add ''gas and/or liquid'' before ''fluid flow'' for consistency with other provisions of the final rule and to clarify that the reference applies to all fluid flow.

Based on consideration of relevant comments, BSEE also revised final paragraph (c)(2)(v) to clarify the meaning of ''flowline'' FSVs and to remove the references to appendix D, section D4, table D2, and subsection D of API RP 14C (while retaining the requirement to use the test procedure in API RP 14C).

As suggested by comments, BSEE revised paragraph (c)(3)(ii) to include ''gas'' detection systems. BSEE added a statement in final paragraph (c)(3)(iii)(A) to clarify that the operator must test all stations for functionality at least once each calendar month, not to exceed 6 weeks between tests, and that no station may be reused until all stations have been tested. This revision ensures proper testing of the ESD stations. Similar changes were made, with different timeframes, to paragraphs (c)(3)(iii)(B) and (C).

BSEE restructured proposed paragraph (c)(5), renumbered it as paragraph (d), and revised and reworded many of the subordinate paragraphs for clarity.

BSEE also moved the provision that limits the time (*i.e.,* 24 months) that a completed subsea well may be disconnected from monitoring capability from proposed paragraph (c)(5)(vi) to final paragraph (d)(1).

Subsequent paragraphs were renumbered and revised for clarification. Several paragraphs were also separated into short subparagraphs. BSEE made these changes to make the requirements easier to read and understand. However, BSEE did not make any substantive changes to the requirements in this section.

Comments and responses—BSEE received public comments on this section and responds to the comments as follows:

Allowable Leakage Rate for Undersea Production Systems

Comment—BSEE received comments concerning changes to the allowable leakage rate for undersea production systems and BSEE's reasoning for proposing to raise those rates. Multiple commenters mentioned that BSEE based its proposed decision to raise the allowable leakage rate partly on the SWRI report on Project #272. (*See* n. 20, *supra*). The commenters asserted that the report recommended conducting a full hazard study, but that the proposed rule did not provide results of that study or indicate that it had been completed. The commenters requested additional technical justification for BSEE's decision. Other commenters suggested that a safety system with leaks should not be allowed at all, asserting that ''[p]roduction safety systems that leak should not pass a safety test'' and ''[c]ritical production safety systems should not leak.''

Response—BSEE disagrees with the suggestion that the proposed decision on leakage rates was based solely on SWRI report #272. BSEE based its decision to increase allowable leakage rates in production systems on several factors, including industry standards (such as API RP 14B), consistency with prior DWOP approvals, and the SWRI report #272.

BSEE also disagrees with the suggestion that it should not allow any leaking valves as part of an approved safety system. This section specifies the allowable leakage rates for valves that are part of a closed system within the production safety system. There are certain critical valves, such as the BSDV, that cannot have any leakage. There are other valves, however, for which some leakage is allowable. For example, BSEE is increasing the allowable leakage rates on SSSVs, as they are part of a closed safety system, designed to diminish the risk of oil spills by stopping the flow within the system in the event that the riser is damaged. The allowable leakage from SSSVs is contained within the closed system; it is not released into the environment. In addition, these new rates are consistent with accepted industry standards.

Testing Flowline FSVs

Comment—A commenter noted that proposed § 250.880(c)(2) included testing requirements for surface valves. In particular, proposed paragraph (c)(2)(v) would have required testing once each calendar month, not to exceed 6 weeks between tests, and would have also required that all FSVs be tested in accordance with the test procedure specified in API RP 14C, Appendix D, section D4, table D2 subsection D. The commenter asserted that, while this section in API RP 14C appears to apply to flowline FSVs, the proposed regulation was not clear, since it stated that the testing requirements would apply to ''surface valves,'' including PSVs, Automatic inlet SDVs actuated by a sensor on a vessel or compressor, SDVs in liquid discharge lines and actuated by vessel low-level sensors, and SSVs. Thus, the commenter asserted that this proposed provision would have applied the specific API RP 14C procedure to surface valves throughout the production process and not just valves covered by section A–1 of API RP, 14C which pertains to ''Wellheads and Flowlines.'' The commenter suggested that, if BSEE intended the proposed testing requirements to apply to ''flowline'' FSVs, then BSEE should insert ''flowline'' before ''FSVs'' in paragraph (c)(2)(v).

Response—BSEE agrees with the substance of this comment and has revised final paragraph (c)(2)(v) to clarify that it applies to flowline FSVs and that flowline FSVs are the only FSVs that must be leak tested under this provision.

Fire- (Flame, Heat, or Smoke) Detection System Testing

Comment—A commenter suggested that BSEE revise proposed § 250.880(c)(3) requirements for fire detections systems to refer to: ''Fire (flame, heat, or smoke) and Gas (combustible) detection systems'' or that BSEE include a separate item (ix) for combustible gas detection. In addition, the commenter suggested that BSEE remove the proposed requirement that all combustible gas-detection systems must be calibrated every 3 months from proposed paragraph (c)(3)(ii) and move that provision to a separate paragraph on combustible gas detection.

Response—BSEE agrees with the commenter's point that there could have been some confusion between the item names and the testing requirements in paragraph (c)(3)(ii) with regard to gas detection systems. However, instead of adopting all of the changes suggested by the commenter, BSEE revised the item name for final paragraph (c)(3)(ii) to include ''gas detection.'' This is consistent with API RP14C; and BSEE added the reference to gas detection systems in this paragraph of the final rule to emphasize the need to test those systems.

3-Barrier Concept for Undersea Valves

Comment—BSEE received multiple comments regarding the 3-barrier concept for undersea valves. The commenters expressed concern that the proposed language would not allow sufficient flexibility for compliance. They asserted that some subsea well may not be equipped with more than one USV or an additional tree valve that could serve in that capacity and that not all tree designs can test multiple barriers.

Response—No changes are necessary. BSEE is not aware of any subsea trees that do not have a second USV. Under final paragraph (d) of this section, the 3 pressure barriers are only required in subsea wells that are shut-in and disconnected from monitoring capability for more than 6 months.

Pumps for Firewater Systems

Comment—A commenter stated that the proposed rule referred to an inspection requirement that is not included in the existing regulations. The commenter asserted that, under the existing regulations, pumps for firewater systems were required to run and be tested for operation and pressure on a weekly basis, while the proposed rule would add an annual inspection for pump performance (flow volume and delivery pressure) to ensure the pump system satisfies the system design requirements. The commenter asserted that BSEE had not identified the rationale for this added inspection or any benefit that it would produce. The commenter recommended that this section be deleted in its entirety until BSEE fully evaluated the content of API RP 14G and the potential value of this requirement.

Response—No changes are necessary based on this comment. In this section, BSEE is not referencing the entire API RP 14G standard; this provision only refers to section 7.2 of the standard. This annual inspection requirement was added to ensure that the firewater pumps are in good working condition since they are a crucial part of the fire safety system. API RP 14G, section 7.2 provides the appropriate details to ensure that the pump inspection is adequate.

Drilling Vessel in the Field or Readily Accessible

Comment—A commenter asserted that proposed paragraph (c)(5)(v) was confusing and seemed excessive since BSEE had not identified the need for having a drilling vessel ''readily available or in the field.'' The commenter suggested that BSEE clarify the intent of this proposed rule. The commenter also suggested that BSEE clarify the definition of ''in the field or readily accessible'' in paragraph (c)(5)(v) and that BSEE should determine that rigs should not have to be under direct contract to be considered ''readily accessible.'' In addition, the commenter asserted that it is also unclear under what circumstances a ''drilling vessel'' would be required to intervene in a shut-in well that is disconnected from monitoring capability. The commenter stated that maintaining a rig on standby would not be cost-effective (although the commenter provided no details to support that assertion). The commenter recommended revising paragraph (c)(5)(v) to read: ''The designated operator/lessee must ensure that a drilling vessel capable of intervention into the disconnected well must be available to the operator for use should the need arise until the wells are brought on line.''

Response—No changes are necessary based on this comment. The regulation states that the drilling vessel must be ''in the field or readily accessible.'' This means that a rig needs to be reasonably available; the rule does not state or imply that the drilling vessel must be under direct contract to be considered readily accessible. The regulation is intended to require that an operator have a rig reasonably available that can respond in a reasonable timeframe, and this is only required for subsea wells that are shut-in and disconnected from monitoring capability for periods greater than 6 months. This provision requires this precaution in order to reduce the risks that a prudent operator is reasonably likely to encounter in the event that other safety systems on the well fail.

BSDV Leakage Rates

Comment—A commenter suggested clarifying proposed § 250.880(c)(4)(iii), regarding testing of BSDVs, by inserting the words ''and BSDVs'' in the third sentence in that paragraph so that it reads: ''You must test according to API RP 14H for SSVs and BSDVs (incorporated by reference as specified in § 250.198).'' The commenter also suggested revising the next sentence in that paragraph by replacing the phrase ''if any fluid flow is observed during the leakage test'' with ''if fluid leakage exceeding the criteria specified in API RP 14H is observed during the leakage test . . .''.

Response—No changes are necessary based on this comment. The BSDV is the surface equivalent of an SSV on a surface well and is critical to ensuring the safety of personnel on the facility as well as protection of the environment. Because the BSDV is a critical component of the subsea system, it is necessary that this valve has rigorous testing criteria. Thus, the BSDV cannot have any fluid flow during the leakage test.

Records (§ 250.890)

Section summary—BSEE has moved the contents of existing § 250.804(b), specifying the records for installed safety devices that operators must maintain, to final § 250.890 and revised the contents for greater clarity and use of plain language. The final rule also codifies new information requirements, as proposed, to assist BSEE in contacting operators.

Regulatory text changes from the proposed rule—The term ''platforms'' was changed to ''facilities'' in paragraph (c), and the term ''person in charge'' was changed to ''primary point of contact for the facility'' in paragraph (c)(2).

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Designated Person in Charge

Comment—One commenter questioned whether the proposed rule would require a facility owner to report a change in the ''designated person in charge'' of welding—as specified in §§ 250.111 and 250.113—or a change of the ''designated person in charge'' as required by USCG regulations. The commenter also asked whether the proposed rule would require a facility owner who designates a separate ''person in charge'' for each of the day and night shifts to submit two reports daily.

Response—BSEE agrees that the proposed language in paragraph (c) was somewhat unclear, and has revised this provision in the final rule to clarify that the person referred to is the ''primary point of contact'' for the facility, who must be included on the facility's contact list. This section ensures that BSEE has a way to contact the facility, when needed, and does not require daily reporting to BSEE. The operator is required to update this list annually and whenever the contact information changes.

Facility Instead of Platform

Comment—A commenter requested clarification of the term ''platform'' as used in proposed paragraph (c). The commenter asked whether that term includes FPSs, FPSOs, TLPs, and MODUs. The commenter also requested clarification on the responsibilities for MODU owners and lease operators for submitting the required contact information if this section does consider MODUs to be platforms.

Response—BSEE agrees that the use of the word ''platforms'' in paragraph (c) could cause some confusion, so we replaced that term with the word ''facilities'' in the final rule. For purposes of this paragraph, facilities include FPSs, FPSOs, and TLPs.

Confirming Compliance

Comment—A commenter asserted that this proposed section included no method for BSEE to confirm compliance. The commenter recommended that BSEE consider third-party oversight in the form of an annual inspection of records or spot-checks of material maintenance and management programs. The commenter suggested that BSEE could use the proposed rule section to create positive reinforcement mechanisms.

Response—No changes are necessary based on this comment. BSEE has confidence in its inspection program's ability to confirm compliance. BSEE's inspectors confirm that the operators are in compliance with BSEE regulations through a number of methods, including verifying records and documentation. (*See, e.g.,* § 250.132(b)(3).) Thus, the third-party approach recommended by the commenter would appear to be less thorough than BSEE's current inspection program. In the future, BSEE may consider additional ways to verify documentation and confirm compliance.

Safety Device Training (§ 250.891)

Section summary—The final rule recodifies existing § 250.805, pertaining to training for personnel who install, inspect, test, and maintain safety devices and for personnel who operate production facilities as final § 250.891. The wording of this section was changed to more accurately capture the scope of subpart S training requirements.

Regulatory text changes from the proposed rule—BSEE added a reference to subpart O, in addition to the reference to subpart S.

Comments and responses—BSEE received public comments on this section and responds to those comments as follows:

Referencing Subparts O and S

Comment—A commenter questioned whether it was BSEE's intent to remove the prescriptive training requirements of subpart O and replace them with the performance-based requirements of subpart S. If so, the commenter suggested that portions of subpart O should be revoked; if not, the commenter suggested that subpart O as well as subpart S should be referenced.

Response—BSEE agrees with the commenter's suggestion about referring to subpart O in this section. Accordingly, BSEE has changed the section to require that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices, and personnel operating production platforms, be trained according to the procedures in subpart O and subpart S. The requirements of subpart O are not affected by this rule; likewise subpart S neither replaces nor supersedes the requirements in subpart O. Rather, those two subparts complement each other. Subpart S provides the general requirements for training, and subpart O provides more detailed training requirements for well control and production safety. If the operator complies with subpart O, then that operator also meets some of the training requirements for subpart S.

Mandatory Training

Comment—One commenter asserted that it is important to human and environmental health that oil and gas production companies understand all the requirements and components associated with drilling, and have an effective quality management system in place. The commenter suggested that initial and periodic training sessions be mandatory for all oil and gas production operations employees, and that personnel be properly trained and qualified to perform their assigned functions, in accordance with subpart O.

Response—No changes to this section are needed in response to this comment. Given the multitude of different jobs associated with offshore production, it is impractical for this rule to establish specific training requirements for each job. However, BSEE regulations under subpart S require operators to address appropriate personnel training through their SEMS plans. SEMS requires everyone who works offshore to be ''trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts.'' § 250.1915. In addition, subpart O provides some specific requirements for training. Among other subpart O requirements, § 250.1503(a) requires operators to implement training programs so that all employees can competently perform their assigned duties, including well control and production safety duties. By requiring operators to ensure that their personnel are trained in accordance with the procedures in subparts O and S, final § 250.891 substantially satisfies the commenter's concern that only qualified personnel perform production operations functions.

Subpart O

Comment—While recognizing the intent behind the proposal to move training from the subpart O requirements to subpart S, one commenter asserted that subpart O is still valid, since it has not been withdrawn from the regulations. The commenter stated that subpart O offers more detail on training program requirements, compared to subpart S, and it is an established basis for all operators' production safety systems and well control training programs. The commenter also asserted that the proposed rule would impose detailed requirements on the operator that are neither specifically required under subpart S nor recommended in API RP 75 (Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities). The commenter recommended that BSEE revise this section to reflect subpart O and not subpart S.

Response—BSEE largely agrees with the commenter's statements concerning the continued applicability of subpart O training requirements for personnel performing functions covered by this final rule. Proposed § 250.891 was not intended to override subpart O; nor does subpart S replace or supersede the requirements in subpart O. As already discussed, the two subparts complement each other, in general and as applied to subpart H. For that reason, BSEE disagrees with the commenter's suggestion that § 250.891 should not refer to subpart S. To provide additional clarity on these point, BSEE revised final § 250.891 to expressly refer to subpart O as well as subpart S.

V. Procedural Matters

Regulatory Planning and Review (E.O. 12866 and E.O. 13563)

E.O. 12866 provides that the Office of Information and Regulatory Affairs (OIRA) will review all significant regulatory actions. A significant regulatory action is one 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;
- 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 has concluded, and OIRA has determined, that this rule is not a significant action under E.O. 12866. In particular, BSEE has concluded, and OIRA has determined, that this final rule will not have an annual economic impact of $100 million or more and will not have a material adverse effect on the economy, the environment, public health or safety, or governmental communities. In support of that determination, BSEE prepared an economic analysis to assess the anticipated costs and potential benefits of the rulemaking. The following discussions summarize the final economic analysis; a complete copy of the final economic analysis can be viewed at *www.Regulations.gov* (use the keyword/ID ''BSEE–2012–0005'').

1. Need for Regulation

As discussed in part II of this document, BSEE identified a need to amend and update the oil and gas production safety system regulations in subpart H. The regulations address such issues as production safety systems, subsurface safety devices, and safety device testing. These systems play a critical role in protecting workers and the environment.

Subpart H has not had a major overhaul since it was first published in 1988. Since that time, much of the oil and gas production on the OCS has moved into deeper waters, and the industry has developed and begun employing new technologies, including: Foam firefighting systems; subsea pumping, water flooding, and gas lift; and new alloys and equipment for high temperature and high pressure wells. The subpart H regulations, however, have not kept pace with the technological advancements. Many of the new provisions in the final rule serve to incorporate and codify current industry practices. In addition, the final rule restructures and reorganizes subpart H into shorter, easier-to-read sections and highlights important information for regulated entities. Thus, the final rule will greatly improve the readability and understanding of the production safety system regulations.

2. Regulatory Alternatives Considered by BSEE

In developing this final rule, BSEE considered two major alternatives (in addition to the numerous specific choices previously described in parts III and IV): (1) Make the regulatory changes contained in this final rule; or (2) take no regulatory action and continue to rely on the current regulations, first promulgated in 1988, in combination with the conditions imposed by subsequent permits and plans (*i.e.,* DWOPs), guidance provided to operators in NTLs and other documents, and voluntary compliance by operators with relevant industry standards. However, relying on specific plan and permit decisions and on guidance documents does not optimize regulatory certainty for the regulated industry. In addition, relying on voluntary compliance with industry standards does not ensure, or provide BSEE with adequate means to ensure, that all operators are performing adequately.

BSEE has elected to move forward with alternative 1 and finalize this rule, which codifies existing guidance and relevant standards and best industry practices. This alternative will provide industry with regulatory certainty, as well as with an appropriate balance of prescriptive and flexible, performance-based requirements. It will also provide BSEE with the necessary means to ensure that production safety systems will improve safety and environmental protection on the OCS, resulting in the other benefits described in this summary and the full economic analysis. Alternative 2 would be less costly, but would not provide those benefits to industry or the public.

3. Summary of Economic Analysis

BSEE derived its estimates by comparing the costs and benefits of the new provisions in the final rule to the baseline in accordance with the guidance provided in OMB Circular A–4. In the baseline, BSEE includes costs and benefits of the final rule that already occur as a result of the existing BSEE regulations, industry guidance documents, industry-developed standards and other accepted industry practices with which industry already complies.[27]

The analysis identified a total of 18 provisions that will result in changes from the baseline, which are listed in Table 1 below, categorized by the size of the cost that they impose on industry. The size categories were defined as follows: ''Major Costs'' being costs of at least $1,000 per firm per year, on average as estimated; ''Minor Costs'' being less than $1,000 and greater than $100 per firm per year; and ''Inconsequential Costs'' being less than $100 per firm per year. The number of offshore operators is 99. The cost per firm does not include costs to BSEE (which accounted for only about 0.5 percent of all costs of all provisions). As shown in Table 1, the distribution of costs by provision is extremely skewed, with one of the 18 provisions (specifically, § 250.876, ''Fired and Exhaust Heated Components'') accounting for over 96 percent of all costs to industry from the rule (about $45,000 per firm per year).

Thus, there is only 1 major cost provision of the final rule. There are 7 minor cost provisions (ranging, on average, from $110 to $576 per firm per year), and 10 inconsequential cost provisions (ranging from $2 to $77 per firm per year). The inconsequential costs, in total, account for only $185 per firm per year, or less than 0.4 percent of the cost of the rule to industry.

[27] BSEE's approach to setting the economic baseline in this final rule is consistent with the approach used for the economic analysis of the recent Well Control and Blowout Preventer Systems final rule. (*See, e.g.,* 81 FR 25985.) The economic analysis for the recent Exploratory Drilling on the Arctic OCS final rule used a similar but more conservative approach to determine baseline costs because of the unique characteristics and remote nature of exploratory drilling operation on the Arctic OCS. (*See, e.g.,* 81 FR 46543.)

Accordingly, the cost estimate in the final economic analysis for the Arctic rule included costs related to some requirements that otherwise could have been included in the economic baseline. (*See* 81 FR 46543–46550.).

Table 1. Distribution of Provisions by Type of Cost

Type of Cost	#	Provision	Annual Cost to Industry and BSEE	Cost Per Firm	Percent of Total Costs Per Firm
Major Costs	1	Inspection of fired and exhaust heated components	$ 4,500,000	$ 45,455	96.18
Minor Costs	2	Inspection, testing, and certification of foam firefighting systems	$ 57,014	$ 576	1.22
	3	Approval of temporary quarters and equipment	$ 38,255	$ 281	0.59
	4	Submission of contact lists for OCS platforms	$ 24,301	$ 137	0.29
	5	Certification letters for mechanical and electrical systems installed in accordance with approved designs	$ 18,086	$ 176	0.37
	6	Certification of as-built diagrams and piping and instrumentation diagrams	$ 17,576	$ 162	0.34
	7	Certification for designs of mechanical and electrical systems	$ 17,464	$ 176	0.37
	8	SPPE compliance documentation	$ 10,915	$ 110	0.23
Inconsequential Costs	9	Industry familiarization with the new rule	$ 7,632	$ 77	0.16
	10	SPPE failure reporting procedures	$ 6,618	$ 66	0.14
	11	Requests for exceptions to BAST requirements	$ 910	$ 9	0.02
	12	Changes after approval of chemical firefighting systems	$ 888	$ 8	0.02
	13	Notification of specified production safety issues	$ 734	$ 6	0.01
	14	Emergency action and safety system shutdown	$ 629	$ 2	0.00
	15	Approval for subsea water injection during loss of communication	$ 627	$ 5	0.01
	16	District Manager approval requests	$ 455	$ 5	0.01
	17	Maintenance of as-built piping and instrumentation diagrams	$ 396	$ 4	0.01
	18	Pressure safety low sensor documentation requirements	$ 273	$ 3	0.01
		TOTAL	**$ 4,702,771**	**$ 47,259**	**100.00**

The single major cost provision, § 250.876, will require the fire tube for certain tube-type heaters to be removed and inspected, every 5 years by a qualified third-party. In addition, if removal and inspection indicate tube-type heater deficiencies, operators must complete and document repairs or replacements. Inspection results must be documented, retained for at least 5 years, and made available to BSEE upon request.

BSEE estimates that there are approximately 1,500 fired and exhaust heated components on the OCS that will need to be inspected every 5 years. Based on comments submitted on the proposed rule and the experience of BSEE subject matter experts, the cost associated with each component inspection is estimated to be approximately $15,000. We estimated the average number of component inspections to be 300 per year, resulting in an annual cost to industry of $4.5 million for inspection of fired and exhaust heated components.

Table 2 summarizes the total cost for the final rule over 10 years (2016–25) by types of costs, both undiscounted and discounted (using 3 and 7 percent rates).

Table 2. Total Costs of Rule Over Ten Years (2016-2025), Undiscounted and Discounted

(Thousands of 2016 Dollars)

Type of Costs	10-Year Industry Cost	10-year Government Cost	10-Year Total Cost
Major Cost: Inspection of fired and exhaust heated components (undiscounted)	$45,000	$0	$45,000
Minor Costs (undiscounted)	$1,603	$233	$1,836
Inconsequential Costs (undiscounted)	$183	$8	$192
Total Undiscounted	$46,787	$241	$47,028
Total Discounted 3 Percent Annually			$40,268
Total Discounted 7 Percent Annually			$33,368

The final rule will benefit society (including both the general public and the industry) in two ways: (1) By reducing the probability of incidents resulting in oil spills and worker injuries, and the severity of such incidents if they occur; and (2) by generating cost savings through an increase in allowable leakage rates for certain safety valves under final § 250.880, which reduces the need (and therefore the costs) to replace or repair such valves, (without resulting in oil released into the environment, as previously explained in part IV.C of this document). BSEE has also determined that this provision poses no economic costs to the regulated industry, so its potential economic impact on that industry is only beneficial (due to the potential costs savings).

With respect to oil spills and injuries, however, the magnitude of the potential benefits is uncertain and highly dependent on the actual reductions in the probability and severity of oil spills and injuries that the final rule will achieve.

Due to this uncertainty, BSEE could not perform a standard cost-benefit analysis to estimate the net benefits of the final rule. As is common in situations where regulatory benefits are highly uncertain, we conducted a break-even analysis following OMB guidance in Circular A–4. Break-even analysis estimates the minimum risk reduction that the final rule will need to achieve for the rule to be cost-beneficial. This minimum risk reduction is calculated by dividing the total net costs of a regulation by the costs of incidents the regulation is expected to avoid. For this analysis, the total net costs are calculated by subtracting the equipment cost savings associated with increased allowable leakage rates and safety valves from the total cost of the rule. BSEE divided the total net costs by the costs associated with oil spills and injuries that the regulation might prevent to calculate the break-even risk reduction level.

To analyze potential reductions in oil spills that might result from the final rule, BSEE used data on spill incidences on OCS facilities from the BOEM OCS Case Study.[28] BSEE's analysis resulted in a potential avoided cost from the final rule of $14.9 million (3,995 barrels × $3,720 per barrel of oil spilled).

A similar procedure was used to estimate the level of benefits resulting from potentially avoided injuries. (Avoided fatalities were not considered because BSEE determined that there were no past fatalities that could be directly connected to the provisions related to the final rule.) Table 3 presents estimated injury levels (for all BSEE Regions where there has been production activity from 2007 through 2013), which we then used to calculate an annual estimated average number of injuries (214). These injury levels were estimated based on the numbers of past injuries reported to BSEE (or MMS) by facilities that would be affected by the rule. (These estimates are explained in greater detail in the final economic analysis document in the regulatory docket.)

[28] Source: United States Department of the Interior, Bureau of Ocean Energy Management, 2012. ''Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012–2017.'' BOEM OCS Study 2012–2022. *http://tinyurl.com/zqr68kq.*

Table 3. Estimated Number of Injuries Per Year

Year	Gulf	Pacific	Total*
2007	299	12	311
2008	225	10	235
2009	202	11	213
2010	193	8	202
2011	151	13	163
2012	179	24	203
2013	160	15	175
Total	1,408	93	1,501
Annual Average	201	13	214

*Note: The totals per year do not always add because of rounding.

We then used that annual average to estimate the number of injuries that could potentially be avoided by the final rule. BSEE then estimated the corresponding benefits by multiplying the average annual number of avoided injuries (214) by the values ascribed to injuries in previous BSEE regulatory analyses (about $47,000 per injury). These calculations resulted in an annual average of potential avoided cost of injuries of $10.1 million, and potential avoided costs from both spills and injuries of roughly $25.0 million. (*See* Table 4.)

Table 4. Estimation of the Potential Consequences from Incidents

Type of Incident	Average Number Per Year	Cost Per Barrel or Per Injury (thousands of 2016 dollars)	Avoidable Cost (millions of 2016 dollars)
Barrels of Oil Spilled	3,995	$3.7	$14.9
Injuries	214	$47.2	$10.1
Total Potential Annual Avoided Cost			$25.0
Total 10-year Cost of Potential Consequences (Undiscounted)			$249.8
Total 10-year Cost of Potential Consequences (3 percent Discounting)			$219.5
Total 10-year Cost of Potential Consequences (7 percent Discounting)			$187.8

In addition to estimating the break-even risk reduction level (*see* discussion and Table 5 below), BSEE used a risk-based approach to cost-benefit analysis to estimate the potential net benefits of the final rule over a range of possible risk reduction levels. Risk-based cost-benefit analysis involves estimating net benefits over a range of risk reduction levels that the regulation could achieve.

Using the estimated costs, cost savings, and potential benefits (in terms of avoided costs of oil spill incidents) of the final rule, BSEE calculated the break-even risk reduction level using discount rates of 3 and 7 percent over a period of 10 years.

As presented in Table 5, the break-even risk reduction level is 12.7 percent (undiscounted), 12.2 percent (3 percent discount rate), and 11.6 percent (7 percent discount rate). At these levels of risk reduction, there would be between 25 and 27 fewer injuries each year. This result demonstrates that a relatively small reduction in the risk of oil spill incidents on affected OCS facilities will be needed for the final rule to be cost-beneficial.

Table 5. Estimation of the Break-even Risk Reduction Level (10 Years)

	Undiscounted	3 percent Discount Rate	7 percent Discount Rate
	(millions of 2016 dollars)		
Total Cost	$47.0	$40.3	$33.4
Total Cost Savings	$15.4	$13.5	$11.6
Net Costs	$31.6	$26.7	$21.8
Potential Avoided Consequences of an Oil Spill	$249.8	$219.5	$187.8
Break-Even Risk Reduction Level	**12.7 percent**	**12.2 percent**	**11.6 percent**

For the second set of benefits, identified as a cost savings to industry, BSEE estimated a net cost (total cost minus total savings) for the final rule. To estimate the potential cost savings to operators from no longer needing to repair or replace certain safety valves as often as under the existing rules, due to higher allowable leakage rates under the final rule, BSEE used data from inspection records for OCS facilities affected by the rule. Of the active wells on the OCS, there have been, on average, 57 occurrences per year of valve repair or replacement associated with the existing allowable leakage rates that could be affected by the increased allowable leakage rates under the final rule. Based on comments submitted on the proposed rule and on the experience of BSEE subject matter experts, we estimated that the potential costs from the repair or replacement of the safety valves would be $22,000 in labor costs and an additional $5,000 in equipment replacement costs per repair/replacement. Thus, BSEE estimated the annual avoided costs from increasing the allowable leakage rates for certain valves to be approximately $1.54 million, based on an estimated average of 57 repairs or replacements avoided per year.

After consideration of all of the potential impacts of this final rule, as described here and in the final economic analysis, BSEE has concluded that the societal benefits of the final rule justify the societal costs.

A. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612, requires agencies to analyze the economic impact of regulations when there is likely to be a significant economic impact on a substantial number of small entities and to consider regulatory alternatives that will achieve the agency's goals while minimizing the burden on small entities. Section 605 of the RFA allows an agency to certify a rule, in lieu of preparing an analysis, if the regulation will not have a significant economic impact on a substantial number of small entities. Further, the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), Public Law 104–121, (March 29, 1996), as amended, requires agencies to produce compliance guidance for small entities if the rule has a significant economic impact on a substantial number of small entities.

For the reasons explained in this section, BSEE has determined that the rule is not likely to have a significant economic impact on a substantial number of small entities and, therefore, that a regulatory flexibility analysis for the final rule is not required by the RFA. Nonetheless, we have included the equivalent of a final regulatory flexibility analysis to assess the impact of this rule on small entities, which is included in the full economic analysis available in the public docket for this rulemaking at *www.regulations.gov*.

Small Business Regulatory Enforcement Fairness Act

The rule is not a major rule under the Small Business Regulatory Enforcement Fairness Act, Public Law 104–121, (March 29, 1996), as amended. This rule:

1. Will not have an annual effect on the economy of $100 million or more. This rule revises the requirements for oil and gas production safety systems. The changes will not have a significant impact on the economy or any economic sector, productivity, jobs, the environment, or other units of government. Most of the new requirements are related to inspection, testing, and paperwork requirements, and will not add significant time to development and production processes. The complete annual compliance cost for each affected small entity is estimated at $8,183.

2. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

3. Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. The requirements will apply to all entities undertake oil and gas production operations on the OCS.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the actions of BSEE, call 1–888–734–3247. You may comment to the Small Business Administration (SBA) without fear of retaliation. Allegations of discrimination/retaliation filed with the SBA will be investigated for appropriate action.

Unfunded Mandates Reform Act of 1995

This rule will not impose an unfunded mandate that may result in State, local, or tribal governments or in private sector expenditures, in the aggregate, of $100 million or more in any one year. The rule will not have a significant or unique effect on State, local, or tribal governments. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

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 interfering with constitutionally protected property rights. A Takings Implications 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.

BSEE has the authority to regulate offshore oil and gas production. State governments do not have authority over offshore oil and gas production on the OCS. None of the changes in this rule will affect areas that are under the jurisdiction of the States. It will not change the way that the States and the Federal government interact, or the way that States interact with private companies.

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, 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 contains clear legal standards.

Consultation With Indian Tribes (E.O. 13175)

Under the Department's tribal consultation policy and under the criteria in E.O. 13175, we have evaluated this rule and determined that it has no substantial direct effects on federally recognized Indian tribes and that consultation under the Department's tribal consultation policy is not required.

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 250, subpart H, *Oil and Gas Production Safety Systems.* The OMB approved the collection under Control Number 1014–0003, expiration August 31, 2019, containing 95,997 hours and $5,582,481 non-hour cost burdens. Potential respondents comprise Federal OCS oil, gas, and sulfur operators and lessees. Responses to this collection of information are mandatory or are required to obtain or retain a benefit. The frequency of responses submitted varies depending upon the requirement; but are usually on occasion, annually, and as a result of situations encountered. The ICR 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 previously stated, BSEE received 57 sets of comments from individual entities (companies, industry organizations, or private citizens). BSEE's responses to comments pertaining to the PRA can be found in IV.C. (Response to Comments and Section-by-Section Summary) of this document.

Since the original publication of the proposed rule, the ICR for subpart H has been renewed and as a result some of the burden hours and non-hour cost burdens have increased/decreased based on outreach performed during the renewal process. We have accounted for the revised burdens in this final rule as follows:

§§ 250.814(a), 250.815(b), 250.828(a), and 250.829(b)—NEW: Alternate setting depth requests was identified as information collection (+1 hour);

§§ 250.827 and 250.869(a)(3)—NEW: Alternative Procedures is covered under subpart A (−3 hours);

§ 250.837(b)(2)—Submit plan to shut-in wells affected by a dropped object is covered under APD or APM (−2 hours);

§ 250.841(b)—NEW: Temporary repairs to facility piping requests was identified as information collection (+780 hour);

§ 250.852(c)(2)—NEW: Request a different sized PSV was listed as 1 hour, 1 response, 5 total burden hours, while it should have been 1 hour, 1 response, 1 total burden hour (−4 hours);

§ 250.855(a)—NEW: Uniquely identify all ESD stations (Note: while this is considered usual and customary business practice, not all companies have done this correctly. The burden listed is only for those who have new floating facilities) (+32 hours);

§ 250.876—NEW: Document and retain, for at least 5 years, all tube-type heater information/requirements; make available to BSEE upon request (+300 hours);

§ 250.880(a)(3)—NEW: Notify BSEE and receive approval before performing modifications to existing subsea infrastructure (+10 hours);

§ 250.802(c)(1)—NEW: Independent third-party for reviewing and certifying various statements (+$550,000);

§ 250.861(b)—NEW: Send foam concentrate sample(s) to authorized representative for quality condition testing (+$209,000); and

§ 250.876—NEW: Have qualified third party remove and inspect, and repair or replace as needed, fire tube (+$4,500,000).

Also, between the proposed and final rulemaking, the cost recovery fees under 30 CFR 250.125 increased based on a final rule published on October 1, 2013 (78 FR 60208), which affects several of the applications subject to this final rule. The most current approved fees and burden hours pertaining to subpart H are listed in the following burden table. While the fees for each affected application increased, the number of applications went down and the remainder of the regulatory requirement burdens in the ICR increased. These changes resulted in a net decrease for non-hour cost burdens (−$20,313) and a net increase for burden hours (+29,218).

As stated previously, this final rule also applies to one regulation under 30 CFR part 250, subpart A, General (§ 250.107(c)). Once this final rule becomes effective, the paperwork burden associated with subpart A will be removed from this collection of information and consolidated with the IC burdens under OMB Control Number 1014–0022.

BURDEN TABLE

Citation 30 CFR Part 250, Subpart A	Reporting and Recordkeeping Requirement*	Hour Burden	Average No. of Annual Responses	Annual Burden Hours
107(c)(3)	**NEW:** Request waiver by demonstrating the use of BAST would not be practicable.	5	2 justifications	10
Subtotal			**2 responses**	**10 hours**
Citation 30 CFR Part 250 Subpart H and NTL(s)	**Reporting and Recordkeeping Requirement***	**Hour Burden**	**Average No. of Annual Responses**	**Annual Burden Hours (rounded)**
		Non-Hour Cost Burdens		
804; 805; 826; 828(c); 834; 838; 839; 870; 873; 874; 875; 880	References to Deepwater Operations Plans (DWOPs).	Burdens are covered under 1014-0024.		
804; 837(b)(2)	Reference to Applications for Permit to Drill (APD).	Burdens are covered under 1014-0025.		
804; 813; 828(b); 837(b)(2)	Reference to Applications for Permit to Modify (APM).	Burdens are covered under 1014-0026.		
800 – 890	Request approval to use new or alternative procedures or equipment; or departures to the operating requirements along with supporting documentation if applicable.	Burdens are covered under 1014-0022.		
General Requirements				
800(a)	Requirements for your production safety system application.	Burden included with specific requirements below.		0
800(a); 880(a)(1), (2)	Prior to production, request approval and pre-production inspection; notify BSEE 72 hours before commencement; notify upon commencement of production.	1	41 requests	41
801(c)	Request evaluation and approval from OORP that includes all relevant information of other quality assurance programs by appropriate qualified entity; or third-party certification mark covering manufacture of SPPE.	34	1 request	34
852(e)(4);	**NEW:** Submit statement/certification for: alternate quality management system, exposure functionality; pipe is suitable and manufacturer has complied with IVA; suitable firefighting foam per original manufacturer specifications; make documentation accessible to BSEE.	Not considered IC under 5 CFR 1320.3(h)(1).		0
801(c);	**NEW:** Independent third-party for reviewing	$500 for 1,100 reviews = $550,000		

802(c)(1);	and certifying various statements throughout this subpart.**			
802(c)(5, (e)	**NEW:** Document all manufacturing, traceability, quality control, installation, testing, repair, redress, performance, and inspection requirements, *etc*. Retain all required documentation of SPEE equipment until 1 year after the date of decommissioning the equipment.	2	30 documents	60
803(a), (d)	**NEW:** Within 30 days of discovery and identification of SPPE failure, provide a written notice of equipment failure to manufacturer and Chief, OORP, or designee.	2	10 notices	20
803(b), (d)	**NEW:** Document and determine the results of the SPPE failure within 120 days and corrective action taken; if appropriate, per requirements, give copy of report to manufacturer and Chief, OORP, or designee.	5	10 documents	50
803(c), (d)	**NEW:** Submit to Chief of OORP or designee modified procedures you made if notified by manufacturer of design changes or you changed operating or repair procedures as result of a failure, within 30 days of changes.	2	1 submittal	2
804(a); 805(b)	Submit detailed info regarding installing SSSVs and related equipment in an HPHT environment with your APD, APM, DWOP, *etc*.			0
814(a); 815(b); 828(a); 829(b);	**NEW:** BSEE will approve on a case-by-case basis.	1	1 request	1
841(b)	**NEW**: Request District Manager approval of temporary repairs to facility piping not to exceed 30 days.	1	780 requests	780
		Subtotal	**1,974 responses**	**988 hours**
			$550,000 non-hour costs	
Surface and Subsurface Safety Systems – Dry Trees				
810; 816; 830	Submit request for a determination that a well is incapable of natural flow.	14	11 wells	157
	Verify the no-flow condition of the well annually.	¼		
817(b); 869(a)	Identify well with sign on wellhead that sub-surface safety device is removed; flag safety devices that are out of service; a visual indicator must be used to identify the bypassed safety device.	Not considered IC under 5 CFR 1320.3(b)(2).		0
817(b)	Record removal of subsurface safety device.	Burden included in § 250.890 of this subpart.		0
		Subtotal	**11 responses**	**157 hours**
Subsea and Subsurface Safety Systems – Subsea Trees				
831; 833(a), (b); 837(c)(5); 838(c); 874(g)(2),	**NEW:** Notify/contact BSEE: (1) if you cannot test all valves and sensors; (2) 48 hours in advance if monitoring ability affected; (3) primary USV designation changes; designating USV2 or another	Notifications		7
		(1) ½	6	
		(2) 2	1	
		(3) 1	1	
		(4) ½	1	

(h)(1)	qualified valve; (4) resuming production; (5) 12 hours of detecting loss of communication; immediately if you cannot meet value closure conditions.	(5) ½	1	
831	**NEW:** Submit a repair/replacement plan to monitor and test.	2	1 submittal	2
837(a)	**NEW:** Request approval to not shut-in a subsea well in an emergency.	½	10 requests	5
837(b)(2); (c)(2)	**NEW:** Obtain approval to resume production (1) after communication is restored; (2) P/L PSHL sensor.	½	2 approvals	1
838(a)(2); 839(a)(2)	**NEW:** Verify closure time of USV upon request of BSEE.	2	2 verifications	4
838(c)(3)	**NEW:** Request approval to produce after loss of communication - include alternate valve closure table or alternate hydraulic bleed schedule.	2	1 approval	2
		Subtotal	**26 responses**	**21 hours**
	Production Safety Systems			
842;	Submit application, and all required/supporting information, for a production safety system with > 125 components.	26	1 application	26
		$5,426 per submission x 1 = $5,426 $14,280 per offshore visit x 1 = $14,280 $7,426 per shipyard visit x 1 = $7,426		
	25 – 125 components.	19	4 applications	76
		$1,314 per submission x 4 = $5,256 $8,967 per offshore visit x 1 = $8,967 $5,141 per shipyard visit x 1 = $5,141		
	< 25 components.	12	10 application	120
		$652 per submission x 10 = $6,520		
	Submit modification to application for production safety system with > 125 components.	13	174 modifications	2,262
		$605 per submission x 174 = $105,270		
	25 – 125 components.	10	615 modifications	6,150
		$217 per submission x 615 = $133,455		
	< 25 components.	7	345 modifications	2,415
		$92 per submission x 345 = $31,740		
842(b)	**NEW:** Your application must also include all required certification(s) [*i.e.,* hazards analysis, *etc*.,] that the designs for mechanical and electrical systems were reviewed, approved, and stamped by registered professional engineer. [NOTE: Upon promulgation, these certification production safety systems requirements will be consolidated into the application hour burden for the specific components]	6	32 certifications	192
842(c)	**NEW:** Submit a certification letter that the mechanical and electrical systems were installed in accordance with approved designs.	6	32 letters	192

842(d), (e);	**NEW:** Submit a certification letter within 60-days after production that the as-built diagrams, piping, and instrumentation diagrams are on file, certified correct, and stamped by a registered professional engineer; submit all the as-built diagrams.	6 ½	32 letters	208
842(f)	**NEW:** Maintain records pertaining to approved design and installation features and as-built pipe and instrumentation diagrams at either the onshore field office, readily available offshore, or location available to BSEE; make available to BSEE upon request and retain for the life of the facility.	½	32 records	16
		Subtotal	**1,277 responses**	**11,657 hours**
			$323,481 non-hour cost burdens	
	Additional Production System Requirements			
851(a)(2)	**NEW:** Request approval to continue using uncoded pressure and fired vessels beyond 540 days after the effective date of the final rule.	2	1 request	2
851(b); 852(a)(2), (3); 858(b); 865(b)	Maintain most current pressure-recorder information at location available to BSEE for as long as information is valid.	35	658 records	23,030
851(c)(2)	**NEW:** Request approval for activation limits set less than 5 psi.	1	10 requests	10
852(c)(1)	**NEW:** Request approval to vent to some other location.	1	10 requests	10
852(c)(2)	**NEW:** Request a different sized and upstream location of the PSV.	1	6 request	6
852(e)(1)	**NEW**: Review manufacturer's Design Methodology Verification Report and IVA's certificate to ensure compliance.	1	10 reviews	10
852(e)(3)	Submit required manufacturer's design specifications for unbonded flexible pipe.	Burden is covered by the application requirement in § 250.842.		0
855(a)	**NEW:** Uniquely identify all EDS stations. [NOTE: while this is considered a usual and customary business practice, not all companies have done this correctly. The burden listed is only for those who have new floating facilities.]	8	4 floating facilities	32
855(b)	Maintain ESD schematic listing control function of all safety devices on the platform, field office closest to facility, or at location conveniently available to BSEE for the life of the facility.	18	650 listings	11,700
858(a)(3)	**NEW:** Request approval to use different procedure for gas-well gas affected.	1	1 request	1
859(a)(3), (4)	Post diagram of firefighting system; furnish evidence firefighting system suitable for operations in subfreezing climates.	8	18 postings	144
859(a)(5)	Obtain approval before installing any	Burden is covered by the		0

	firefighting equipment.	application requirement in § 250.842.		
859(c); 860(b), (c); related NTL(s)	Request approval to use a chemical-only fire system in lieu of a water system (including extensions up to 7 days of your approved request) by submitting, including but not limited to, submittal of justification and risk assessment (and all relevant information listed in the table of this section).	39	23 requests	897
860(d)	**NEW:** Change(s) made after approval rec'd re 860(b) - document change; maintain the revised version at facility or closest field office for BSEE review/inspection; submit new request w/updated risk assessment for approval; maintain for life of facility.	½	14 changes	7
861(b)	**NEW:** Annually conduct inspection of foam concentrates and tanks; make documentation of foam available to BSEE.	2	500 submittals	1,000
	NEW: Send foam concentrate sample(s) to authorized representative for quality condition testing.**	$418 per sample x 500 samples = $209,000.		
864	Maintain erosion control program records for 2 years; make available to BSEE upon request.	21	645 records	13,545
867(a)	**NEW:** Request approval to install temporary quarters.	6	1 request	6
867(b)	**NEW:** Submit supporting information/ documentation if required by BSEE to install a temporary firewater system.	1	1 request	1
867(c)	**NEW:** Request approval to use temporary equipment for well testing/clean-up.	1	300 requests	300
869(f)	Label all pneumatic control panels and computer-based control stations according to API RP 14C nomenclature.	Not considered IC under 5 CFR 1320.3(b)(2).		0
870(a)	**NEW:** Document PSL on your field test records w/delay greater than 45 seconds.	½	6 records	3
874(g)(3)	**NEW:** Submit request with alternative plan ensuring subsea shutdown capability.	2	5 requests	10
874(h)(2)	**NEW:** Request approval to continue to inject w/loss of communication.	1	5 requests	5
876	**NEW:** Document and retain, for at least 5 years, all tube-type heater information / requirements; make available to BSEE upon request. Have qualified 3rd party remove and inspect, repair or replace fire tube.**	1	300 documents	300
		$15,000 x 1,500 inspections / once every 5 years = 300 inspections = $4,500,000		
		Subtotal	**3,168 responses**	**51,019 hours**
			$4,709,000 non-hour cost burdens	
	Safety Device Testing			
880(a)(3)	**NEW:** Notify BSEE and receive approval before performing modifications to existing subsea infrastructure.	½	20 requests	10
880(d)(1)	**NEW:** Request approval for a well that is completed and disconnected from	1	1 request	1

	monitoring capability more than 24 months.			
		Subtotal	**21 response**	**11 hour**
	Records and Training			
890(a), (b)	Maintain records for 2 years on subsurface and surface safety devices to include, but not limited to, status and history of each device; installation date and details, inspection, testing, repair, removal, adjustments, reinstallation, *etc.*; at field office nearest facility AND a secure onshore location; make records available to BSEE.	48	658 records	31,584
890(c)	**NEW:** Submit annually a contact list (w/all required information) for all OCS operated facilities or submit when revised.	½	1,000 annual lists	550
		½	100 revised lists	
		Subtotal	**1,758 responses**	**32,134 hours**
Total Burden Hours			**8,237 Responses**	**95,997 Hours**
			$5,582,481 Non-Hour Cost Burdens	

* In the future, BSEE may require electronic filing of certain submissions.

** In the proposed rule, this burden was overlooked.

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; email *kye.mason@bsee.gov*, or fax (703) 787–1093.

National Environmental Policy Act of 1969 (NEPA)

We prepared a final environmental assessment to determine whether this final rule will have a significant impact on the quality of the human environment under NEPA and have concluded that it will not have such an impact. This rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under NEPA is not required because we reached a Finding of No Significant Impact. A copy of the Environmental Assessment and Finding of No Significant Impact can be viewed at *www.regulations.gov* (use the keyword/ID BSEE–2012–0005).

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 likely to have a significant adverse effect on the supply, distribution, or use of energy, and therefore it is not a significant energy action under the definition in E.O. 13211. 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, Government contracts, Incorporation by reference, Investigations, Oil and gas exploration, Penalties, Pipelines, Outer Continental Shelf—mineral resources, Outer Continental Shelf—rights-of-way, Reporting and recordkeeping requirements, Sulfur.

Dated: August 24, 2016.

Amanda Leiter,

Acting 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; 33 U.S.C. 1321(j)(1)(C); 43 U.S.C. 1334.

■ 2. Amend § 250.107 by revising paragraph (c), removing paragraph (d), and redesignating paragraph (e) as paragraph (d) to read as follows:

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

* * * * *

(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section.

(3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.

* * * * *

■ 3. Revise the § 250.114 section heading to read as follows:

§ 250.114 How must I install, maintain, and operate electrical equipment?

* * * * *

■ 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 $14,280 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $7,426 for an inspection of a facility while in a shipyard. A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (as incorporated by reference in § 250.198).	§ 250.842.
(6) New Facility Production Safety System Application for facility with 25–125 components.	$1,314 $8,967 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $5,141 for an inspection of a facility while in a shipyard.	§ 250.842.
(7) New Facility Production Safety System Application for facility with fewer than 25 components.	$652	§ 250.842.
(8) Production Safety System Application—Modification with more than 125 components reviewed.	$605	§ 250.842.
(9) Production Safety System Application—Modification with 25–125 components reviewed.	$217	§ 250.842.
(10) Production Safety System Application—Modification with fewer than 25 components reviewed.	$92	§ 250.842.
(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).
(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).

Service—processing of the following:	Fee amount	30 CFR citation
(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 as follows:
■ a. Revise paragraphs (g)(1) through (3);
■ b. Remove paragraphs (g)(6) and (7);
■ c. Redesignate paragraph (g)(8) as (g)(6);
■ d. Revise paragraphs, (h)(1), (51) through (53), (55) through (62), (65), (66), (68), (70), (71), (73), (74), and (93) through (95);
■ e. Add paragraph (h)(96).

The revisions and addition read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(g) * * *

(1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at §§ 250.851(a) and 250.1629(b).

* * * * *

(h) * * *

(1) API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006; incorporated by reference at §§ 250.851(a) and 250.1629(b);

* * * * *

(51) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009; incorporated by reference at §§ 250.292, 250.733, 250.800(c), 250.901(a), (d), and 250.1002(b);

(52) API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008; incorporated by reference at §§ 250.800(c) and 250.901(a), (d);

(53) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007; incorporated by reference at §§ 250.800(c) and 250.901;

* * * * *

(55) ANSI/API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005; incorporated by reference at §§ 250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c);

(56) API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007; incorporated by reference at §§ 250.125(a), 250.292(j), 250.841(a), 250.842(a), 250.850, 250.852(a), 250.855, 250.856(a), 250.858(a), 250.862(e), 250.865(a), 250.867(a), 250.869(a) through (c), 250.872(a), 250.873(a), 250.874(a), 250.880(b) and (c), 250.1002(d), 250.1004(b), 250.1628(c) and (d), 250.1629(b), and 250.1630(a);

(57) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed, January 2013; incorporated by reference at §§ 250.841(b), 250.842(a), and 250.1628(b) and (d);

(58) API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Reaffirmed: April 2013; incorporated by reference at §§ 250.114(c), 250.842(b), 250.862(e), and 250.1629(b);

(59) API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, Reaffirmed: March 2007; incorporated by reference at §§ 250.114(c), 250.842(b), 250.862(e), and 250.1629(b);

(60) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; incorporated by reference at §§ 250.859(a), 250.862(e), 250.880(c), and 250.1629(b);

(61) API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007; incorporated by reference at §§ 250.820, 250.834, 250.836, and 250.880(c);

(62) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed: January 2013; incorporated by reference at §§ 250.800(b) and (c), 250.842(b), and 250.901(a);

* * * * *

(65) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; Errata (August 17, 1998), Reaffirmed November 2002; incorporated by reference at

§§ 250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

(66) API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; Reaffirmed, August 2013; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

* * * * *

(68) ANSI/API Specification Q1 (ANSI/API Spec. Q1), Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Addendum 1, June 2010; incorporated by reference at §§ 250.730, 250.801(b) and (c);

* * * * *

(70) ANSI/API Specification 6A (ANSI/API Spec. 6A), Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; 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, 250.802(a), 250.803(a), 250.833, 250.873(b), 250.874(g), and 250.1002(b);

(71) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed April 2008; incorporated by reference at §§ 250.802(a), 250.833, 250.873(b), and 250.874(g);

* * * * *

(73) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Reaffirmed, June 2012; incorporated by reference at §§ 250.802(b) and 250.803(a);

(74) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008, incorporated by reference at §§ 250.852(e), 250.1002(b), and 250.1007(a).

* * * * *

(93) ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011, incorporated by reference at § 250.730;

(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;

(95) ANSI/API RP 2N, Third Edition, ''Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions'', Third Edition, April 2015; incorporated by reference at § 250.470(g); and

(96) API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009; incorporated by reference at § 250.841(b).

* * * * *

■ 6. Revise § 250.518(d) to read as follows:

§ 250.518 Tubing and wellhead equipment.

* * * * *

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839.

* * * * *

■ 7. Revise § 250.619(d) to read as follows:

§ 250.619 Tubing and wellhead equipment.

* * * * *

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839.

* * * * *

■ 8. Revise subpart H to read as follows:

Subpart H—Oil and Gas Production Safety Systems

General Requirements

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

Surface and Subsurface Safety Systems—Dry Trees

250.810 Dry tree subsurface safety devices—general.
250.811 Specifications for SSSVs—dry trees.
250.812 Surface-controlled SSSVs—dry trees.
250.813 Subsurface-controlled SSSVs.
250.814 Design, installation, and operation of SSSVs—dry trees.
250.815 Subsurface safety devices in shut-in wells—dry trees.
250.816 Subsurface safety devices in injection wells—dry trees.
250.817 Temporary removal of subsurface safety devices for routine operations.
250.818 Additional safety equipment—dry trees.
250.819 Specification for surface safety valves (SSVs).
250.820 Use of SSVs.
250.821 Emergency action and safety system shutdown—dry trees.
250.822–250.824 [Reserved]

Subsea and Subsurface Safety Systems—Subsea Trees

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

Production Safety Systems

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

Additional Production System Requirements

250.850 Production system requirements—general.
250.851 Pressure vessels (including heat exchangers) and fired vessels.
250.852 Flowlines/Headers.
250.853 Safety sensors.
250.854 Floating production units equipped with turrets and turret-mounted systems.
250.855 Emergency shutdown (ESD) system.
250.856 Engines.
250.857 Glycol dehydration units.
250.858 Gas compressors.
250.859 Firefighting systems.
250.860 Chemical firefighting system.
250.861 Foam firefighting systems.
250.862 Fire and gas-detection systems.
250.863 Electrical equipment.
250.864 Erosion.
250.865 Surface pumps.
250.866 Personnel safety equipment.
250.867 Temporary quarters and temporary equipment.

250.868 Non-metallic piping.
250.869 General platform operations.
250.870 Time delays on pressure safety low (PSL) sensors.
250.871 Welding and burning practices and procedures.
250.872 Atmospheric vessels.
250.873 Subsea gas lift requirements.
250.874 Subsea water injection systems.
250.875 Subsea pump systems.
250.876 Fired and exhaust heated components.
250.877–250.879 [Reserved]

Safety Device Testing

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

Records and Training

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

Subpart H—Oil and Gas Production Safety Systems

General Requirements

§ 250.800 General.

(a) You must design, install, use, maintain, and test production safety equipment in a manner to ensure the safety and protection of the human, marine, and coastal environments. For production safety systems operated in subfreezing climates, you must use equipment and procedures that account for floating ice, icing, and other extreme environmental conditions that may occur in the area. You must not commence production until BSEE approves your production safety system application and you have requested a preproduction inspection.

(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J (incorporated by reference as specified in § 250.198);

(c) For all new floating production systems (FPSs) (*e.g.,* column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); and spars), you must:

(1) Comply with API RP 14J;

(2) Meet the production riser standards of API RP 2RD (incorporated by reference as specified in § 250.198), provided that you may not install single bore production risers from floating production facilities;

(3) Design all stationkeeping (*i.e.,* anchoring and mooring) systems for floating production facilities to meet the standards of API RP 2SK and API RP 2SM (both incorporated by reference as specified in § 250.198); and

(4) Design stationkeeping (*i.e.,* anchoring and mooring) systems for floating facilities to meet the structural requirements of §§ 250.900 through 250.921.

(d) If there are any conflicts between the documents incorporated by reference and the requirements of this subpart, you must follow the requirements of this subpart.

(e) You may use alternate procedures or equipment during operations after receiving approval from the District Manager. You must present your proposed alternate procedures or equipment as required by § 250.141.

(f) You may apply for a departure from the operating requirements of this subpart as provided by § 250.142. Your written request must include a justification showing why the departure is necessary and appropriate.

§ 250.801 Safety and pollution prevention equipment (SPPE) certification.

(a) *SPPE equipment.* In wells located on the OCS, you must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. BSEE considers the following equipment to be types of SPPE:

(1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow;

(2) Boarding shutdown valves (BSDV) and their actuators, as of September 7, 2017. For subsea wells, the BSDV is the surface equivalent of an SSV on a surface well;

(3) Underwater safety valves (USV) and actuators; and

(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples.

(b) *Certification of SPPE.* SPPE that is manufactured and marked pursuant to ANSI/API Spec. Q1 (incorporated by reference as specified in § 250.198), is considered as certified SPPE under this part. All other SPPE is considered as not certified, unless approved in accordance with paragraph (c) of this section.

(c) *Accepting SPPE manufactured under other quality assurance programs.* BSEE may exercise its discretion to accept SPPE manufactured under a quality assurance program other than ANSI/API Spec. Q1, provided that the alternative quality assurance program is verified as equivalent to API Spec. Q1 by an appropriately qualified entity and that the operator submits a request to BSEE containing relevant information about the alternative program and receives BSEE approval. In addition, an operator may request that BSEE accept SPPE that is marked with a third-party certification mark other than the API monogram. All requests under this paragraph should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; VAE–ORP; 45600 Woodland Road, Sterling, VA 20166.

§ 250.802 Requirements for SPPE.

(a) All SSVs, BSDVs, and USVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198).

(b) All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in § 250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.

(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, USVs, and SSSVs and their actuators, include, but are not limited to, the following:

(1) Each device must be designed to function and to close in the most extreme conditions to which it may be exposed, including temperature, pressure, flow rates, and environmental conditions. You must have an independent third-party review and certify that each device will function as designed under the conditions to which it may be exposed. The independent third-party must have sufficient expertise and experience to perform the review and certification.

(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.

(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.

(4) You must have requalification testing performed following manufacture design changes.

(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.

(6) You must follow specified installation, testing, and repair protocols.

(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.

(d) You must install and use SPPE according to the following table.

If . . .	Then . . .
(1) You need to install any SPPE . . .	You must install SPPE that conforms to § 250.801.
(2) A non-certified SPPE is already in service . . .	It may remain in service on that well.
(3) A non-certified SPPE requires offsite repair, re-manufacturing, or any hot work such as welding	You must replace it with SPPE that conforms to § 250.801.

(e) You must retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of the SPPE until 1 year after the date of decommissioning of the equipment.

§ 250.803 What SPPE failure reporting procedures must I follow?

(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs and section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs (all incorporated by reference in § 250.198). You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs or to the Chief's designee and to 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 or purpose.

(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that manufacturer and the Chief, Office of Offshore Regulatory Programs or the Chief's designee receives a copy of the analysis report. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.

(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs or the Chief's designee.

(d) Any notifications or reports submitted to the Chief, Office of Offshore Regulatory Programs under paragraphs (a), (b), and (c) of this section must be sent to: Bureau of Safety and Environmental Enforcement; VAE–ORP, 45600 Woodland Road, Sterling, VA 20166.

§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.

(a) If you plan to install SSSVs and related equipment in an HPHT environment, you must submit detailed information with your Application for Permit to Drill (APD) or Application for Permit to Modify (APM), and Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment are capable of performing in the applicable HPHT environment. Your detailed information must include the following:

(1) A discussion of the SSSVs' and related equipment's design verification analyses;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing processes and procedures used; and

(3) An explanation of why the analyses, processes, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

(b) For this section, HPHT environment means when one or more of the following well conditions exist:

(1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psia or a temperature rating greater than 350 degrees Fahrenheit;

(2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psia on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

(3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

(c) For this section, related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

§ 250.805 Hydrogen sulfide.

(a) In zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.490, you must conduct production operations in accordance with that section and other relevant requirements of this subpart.

(b) You must receive approval through the DWOP process (§§ 250.286 through 250.295) for production operations in HPHT environments known to contain H_2S or in HPHT environments where the presence of H_2S is unknown.

§§ 250.806—250.809 [Reserved]

Surface and Subsurface Safety Systems—Dry Trees

§ 250.810 Dry tree subsurface safety devices—general.

For wells using dry trees or for which you intend to install dry trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after you submit a request containing a justification, the District Manager determines the well to be incapable of natural flow. You must install flow couplings above and below the subsurface safety devices. These subsurface safety devices include the following devices and any associated safety valve lock and landing nipple:

(a) An SSSV, including either:

(1) A surface-controlled SSSV; or

(2) A subsurface-controlled SSSV.

(b) An injection valve.

(c) A tubing plug.

(d) A tubing/annular subsurface safety device.

§ 250.811 Specifications for SSSVs—dry trees.

All surface-controlled and subsurface-controlled SSSVs, safety valve locks, and landing nipples installed in the OCS must conform to the requirements specified in §§ 250.801 through 250.803.

§ 250.812 Surface-controlled SSSVs—dry trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§ 250.813, 250.815, and 250.816.

(a) The surface controls must be located on the site or at a BSEE-approved remote location. You may request District Manager approval to situate the surface controls at a remote location.

(b) You must equip dry tree wells not previously equipped with a surface-controlled SSSV, and dry tree wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV, with a surface-controlled SSSV when the tubing is first removed and reinstalled.

§ 250.813 Subsurface-controlled SSSVs.

You may submit an APM or a request to the District Manager for approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, if the subsurface-controlled SSSV is installed in a well equipped with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.

§ 250.814 Design, installation, and operation of SSSVs—dry trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while the SSSV is inoperable, except when flowing the well is necessary for a particular operation such as cutting paraffin or performing other routine operations as defined in § 250.601.

(c) Until the SSSV is installed, the well must be attended in the immediate vicinity so that any necessary emergency actions can be taken while the well is open to flow. During testing and inspection procedures, the well must not be left unattended while open to production unless you have installed a properly operating SSSV in the well.

(d) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

§ 250.815 Subsurface safety devices in shut-in wells—dry trees.

(a) You must equip all new dry tree completions (perforated but not placed on production) and completions that are shut-in for a period of 6 months with one of the following:

(1) A pump-through-type tubing plug;

(2) A surface-controlled SSSV, provided the surface control has been rendered inoperative; or

(3) An injection valve capable of preventing backflow.

(b) When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 250.816 Subsurface safety devices in injection wells—dry trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.817 Temporary removal of subsurface safety devices for routine operations.

(a) You may remove a wireline- or pumpdown-retrievable subsurface safety device without further authorization or notice, for a routine operation that does not require BSEE approval of a Form BSEE–0124, Application for Permit to Modify (APM). For a list of these routine operations, see § 250.601. The removal period must not exceed 15 days.

(b) Prior to removal, you must identify the well by placing a sign on the wellhead stating that the subsurface safety device was removed. You must note the removal of the subsurface safety device in the records required by § 250.890. If the master valve is open, you must ensure that a trained person (see § 250.891) is in the immediate vicinity to attend the well and take any necessary emergency actions.

(c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended by a support vessel, or a pump-through plug must be installed in the tubing at least 100 feet below the mudline and the master valve must be closed, unless otherwise approved by the appropriate District Manager.

(d) You must not allow the well to flow while the subsurface safety device is removed, except when it is necessary for the particular operation for which the SSSV is removed. The provisions of this paragraph are not applicable to the testing and inspection procedures specified in § 250.880.

§ 250.818 Additional safety equipment—dry trees.

(a) You must equip all tubing installations that have a wireline- or pumpdown-retrievable subsurface safety device with a landing nipple, with flow couplings or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform emergency shutdown system (ESD).

(c) In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled SSSVs must close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

§ 250.819 Specification for surface safety valves (SSVs).

All wellhead SSVs and their actuators must conform to the requirements specified in §§ 250.801 through 250.803.

§ 250.820 Use of SSVs.

You must install, maintain, inspect, repair, and test all SSVs in accordance with API RP 14H (incorporated by reference as specified in § 250.198). If any SSV does not operate properly, or if any gas and/or liquid fluid flow is observed during the leakage test as described in § 250.880, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.

§ 250.821 Emergency action and safety system shutdown—dry trees.

(a) In the event of an emergency, such as an impending National Weather Service-named tropical storm or hurricane:

(1) Any well not yet equipped with a subsurface safety device and that is capable of natural flow must have the subsurface safety device properly installed as soon as possible, with due consideration being given to personnel safety.

(2) You must shut-in (by closing the SSV and the surface-controlled SSSV) the following types of wells:

(i) All oil wells, and

(ii) All gas wells requiring compression.

(b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any alternative design-delayed closure time of greater than 2 minutes based on the mechanical/production characteristics of the individual well.

§§ 250.822—250.824 [Reserved]

Subsea and Subsurface Safety Systems—Subsea Trees

§ 250.825 Subsea tree subsurface safety devices—general.

(a) For wells using subsea (wet) trees or for which you intend to install subsea trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency. You must also install flow couplings above and below the subsurface safety devices. For instances where the well at issue is incapable of natural flow, you may seek District Manager approval for using alternative procedures or equipment, if you propose to use a subsea safety system that is not capable of shutting off the flow from the well in the event of an emergency. Subsurface safety devices include the following and any associated safety valve lock and landing nipple:

(1) A surface-controlled SSSV;

(2) An injection valve;

(3) A tubing plug; and

(4) A tubing/annular subsurface safety device.

(b) After installing the subsea tree, but before the rig or installation vessel leaves the area, you must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this subpart.

§ 250.826 Specifications for SSSVs—subsea trees.

All SSSVs, safety valve locks, and landing nipples installed on the OCS must conform to the requirements specified in §§ 250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§ 250.286 through 250.295.

§ 250.827 Surface-controlled SSSVs—subsea trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§ 250.829 and 250.830. The surface controls must be located on the host facility.

§ 250.828 Design, installation, and operation of SSSVs—subsea trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline. When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM.

(c) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

§ 250.829 Subsurface safety devices in shut-in wells—subsea trees.

(a) You must equip all new subsea tree completions (perforated but not placed on production) and completions shut-in for a period of 6 months with one of the following:

(1) A pump-through-type tubing plug;

(2) An injection valve capable of preventing backflow; or

(3) A surface-controlled SSSV, provided the surface control has been rendered inoperative. For purposes of this section, a surface-controlled SSSV is considered inoperative if, for a direct hydraulic control system, you have bled the hydraulics from the control line and have isolated it from the hydraulic control pressure. If your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, a surface-controlled SSSV is considered inoperative if you perform the following:

(i) Disable the control function of the surface-controlled SSSV within the logic of the programmable logic controller which controls the subsea well;

(ii) Place a pressure alarm high on the control line to the surface-controlled SSSV of the subsea well; and

(iii) Close the USV and at least one other tree valve on the subsea well.

(b) When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 250.830 Subsurface safety devices in injection wells—subsea trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.831 Alteration or disconnection of subsea pipeline or umbilical.

If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well would affect your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing. You must not alter or disconnect until the repair or replacement plan is approved.

§ 250.832 Additional safety equipment—subsea trees.

(a) You must equip all tubing installations that have a wireline- or pump down-retrievable subsurface safety device installed after May 31, 1988, with a landing nipple, with flow couplings, or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform ESD.

(c) In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location.

§ 250.833 Specification for underwater safety valves (USVs).

All USVs, including those designated as primary or secondary, and any alternate isolation valve (AIV) that acts as a USV, if applicable, and their actuators, must conform to the requirements specified in §§ 250.801 through 250.803. A production master or wing valve may qualify as a USV under API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198).

(a) Primary USV (USV1). You must install and designate one USV on a subsea tree as the USV1. The USV1 must be located upstream of the choke valve. As provided in paragraph (b) of this section, you must inform BSEE if the primary USV designation changes.

(b) Secondary USV (USV2). You may equip your tree with two or more valves qualified to be designated as a USV, one of which may be designated as the USV2. If the USV1 fails to operate properly or exhibits a leakage rate greater than allowed in § 250.880, you must notify the appropriate District Office and designate the USV2 or another qualified valve (*e.g.,* an AIV) that meets all the requirements of this subpart for USVs as the USV1. The

USV2 must be located upstream of the choke.

§ 250.834 Use of USVs.

You must install, maintain, inspect, repair, and test any valve designated as the primary USV in accordance with this subpart, your DWOP (as specified in §§ 250.286 through 250.295), and API RP 14H (incorporated by reference as specified in § 250.198). For additional USV testing requirements, refer to § 250.880.

§ 250.835 Specification for all boarding shutdown valves (BSDVs) associated with subsea systems.

You must install a BSDV on the pipeline boarding riser. All new BSDVs and any BSDVs removed from service for remanufacturing or repair and their actuators installed on the OCS must meet the requirements specified in §§ 250.801 through 250.803. In addition, you must:

(a) Ensure that the internal design pressure(s) of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum pressure of any input source and complies with the design requirements set forth in subpart J, unless BSEE approves an alternate design.

(b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.

(c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (*i.e.,* within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical).

(d) Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV.

§ 250.836 Use of BSDVs.

You must install, inspect, maintain, repair, and test all new BSDVs and BSDVs that you remove from service for remanufacturing or repair in accordance with API RP 14H (incorporated by reference as specified in § 250.198) for SSVs. If any BSDV does not operate properly or if any gas fluid and/or liquid fluid flow is observed during the leakage test, as described in § 250.880, you must shut-in all sources to the BSDV and immediately repair or replace the valve.

§ 250.837 Emergency action and safety system shutdown—subsea trees.

(a) In the event of an emergency, such as an impending named tropical storm or hurricane, you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, and surface-controlled SSSV.

(b) When operating a mobile offshore drilling unit (MODU) or other type of workover vessel in an area with producing subsea wells, you must:

(1) Suspend production from all such wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline; or

(2) Establish direct, real-time communications between the MODU or other type of workover vessel and the production facility control room and prepare a plan to be submitted to the appropriate District Manager for approval, as part of an Application for Permit to Drill (BSEE–0123) or an Application for Permit to Modify (BSEE–0124), to shut-in any wells that could be affected by a dropped object. If an object is dropped, the driller (or other authorized rig floor personnel) must immediately secure the well directly under the MODU or other type of workover vessel using the ESD station near the driller's console while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the platform and the MODU or other type of workover vessel. If communication is lost between the MODU or other type of workover vessel and the platform for 20 minutes or more, you must shut-in all wells that could be affected by a dropped object.

(c) In the event of an emergency, you must operate your production system according to the valve closure times in the applicable tables in §§ 250.838 and 250.839 for the following conditions:

(1) *Process upset.* In the event an upset in the production process train occurs downstream of the BSDV, you must close the BSDV in accordance with the applicable tables in §§ 250.838 and 250.839. You may reopen the BSDV to blow down the pipeline to prevent hydrates, provided you have secured the well(s) and ensured adequate protection.

(2) *Pipeline pressure safety high and low (PSHL) sensor.* In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system, by closing the BSDVs, USVs, and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must obtain approval from the appropriate District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate District Manager.

(3) *ESD/TSE (platform).* In the event of an ESD activation that is initiated because of a platform ESD or platform TSE not associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(4) *Subsea ESD (platform) or BSDV TSE.* In the event of an emergency shutdown activation that is initiated by the host platform due to an abnormal condition subsea, or a TSE associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(5) *Subsea ESD (MODU).* In the event of an ESD activation that is initiated by a dropped object from a MODU or other type of workover vessel, you must secure all wells in the proximity of the MODU or other type of workover vessel by closing the USVs and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate District Manager before resuming production.

(d) Following an ESD or fire, you must bleed your low pressure (LP) and high pressure (HP) hydraulic systems in accordance with the applicable tables in §§ 250.838 and 250.839 to ensure that the valves are locked out of service and cannot be reopened inadvertently.

§ 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?

(a) If you have an electro-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in paragraphs (b) and (d) of this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP as long as communication is maintained with the platform or with the MODU or other type of workover vessel:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements].
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 60 minutes after sensor activation. If you use a 60-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 24 hours total.	[no requirements].	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close within 5 minutes after ESD or sensor activation. If you use a 5-minute resettable timer, you may continue to reset the time for closure up to a maximum of 20 minutes total.	Close within 20 minutes after ESD or sensor activation.		Close within 20 minutes after ESD or sensor activation. If you use a 20-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 60 minutes total.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation			Close within 10 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel, Dropped object).	[no requirements].	Initiate valve closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed within 10 minutes after ESD activation.

(c) If you have an electro-hydraulic control system and experience a loss of communications (EH Loss of Comms), you must comply with the following:

(1) If you can meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office within 12 hours of detecting the loss of communication.

(2) If you cannot meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office immediately after detecting the loss of communication. You must shut-in production by initiating a bleed of the low pressure (LP) hydraulic system or the high pressure (HP) hydraulic system within 120 minutes after loss of communication. You must bleed the other hydraulic system within 180 minutes after loss of communication.

(3) You must obtain approval from the appropriate District Manager before continuing to produce after loss of communication when you cannot meet the EH Loss of Comms valve closure times specified in the table in paragraph (d) of this section. In your request, include an alternate valve closure timing table that your system is able to achieve. The appropriate District Manager may also approve an alternate hydraulic bleed schedule to allow for hydrate mitigation and orderly shut-in.

(d) If you experience a loss of communications, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM WITH LOSS OF COMMUNICATION

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements].
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after sensor activation).			Initiate closure when HP hydraulic system is bled (close within 24 hours after sensor activation).	Initiate unrestricted bleed immediately, concurrent with sensor activation.	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 20 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 60 minutes after ESD or sensor activation).	Initiate unrestricted bleed concurrent with BSDV closure (bleed within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately, allowing for surface-controlled SSSV closure.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object.	[no requirements].	Initiate closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

§ 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?

(a) If you have a direct-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, DIRECT-HYDRAULIC CONTROL SYSTEM

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements]
(2) Flowline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 24 hours after sensor activation.	Complete bleed of USV1, USV2, and the AIV within 20 minutes after sensor activation.	Complete bleed within 24 hours after sensor activation.

VALVE CLOSURE TIMING, DIRECT-HYDRAULIC CONTROL SYSTEM—Continued

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close all valves within 20 minutes after ESD or sensor activation.			Close within 60 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2, and the AIV within 20 minutes after ESD or sensor activation.	Complete bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.			Close within 10 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2, and the AIV within 10 minutes after ESD or sensor activation.	Complete bleed within 10 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object.	[no requirements].	Initiate closure immediately. If desired, you may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

PRODUCTION SAFETY SYSTEMS

§ 250.840 Design, installation, and maintenance—general.

You must design, install, and maintain all production facilities and equipment including, but not limited to, separators, treaters, pumps, heat exchangers, fired components, wellhead injection lines, compressors, headers, and flowlines in a manner that is efficient, safe, and protects the environment.

§ 250.841 Platforms.

(a) You must protect all platform production facilities with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C (incorporated by reference as specified in § 250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C, you must utilize the analysis technique and documentation specified in API RP 14C to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are contained in § 250.1004.

(b) You must design, install, inspect, repair, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E and API 570 (both incorporated by reference as specified in § 250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

§ 250.842 Approval of safety systems design and installation features.

(a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table:

You must submit:	Details and/or additional requirements:
(1) A schematic piping and instrumentation diagram	Showing the following: (i) Well shut-in tubing pressure; (ii) Piping specification breaks, piping sizes; (iii) Pressure relief valve set points; (iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors and metering devices; (v) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps; (vi) Size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in § 250.198); and (vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E (incorporated by reference as specified in § 250.198).

You must submit:	Details and/or additional requirements:
(2) A safety analysis flow diagram (API RP 14C, Appendix E) and the related Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, subsection 4.3.3) (incorporated by reference as specified in § 250.198).	If processing components are used, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the same analysis technique and documentation to determine the effects and requirements of these components upon the safety system.
(3) Electrical system information, including	(i) A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference as specified in § 250.198). (ii) Identification of all areas where potential ignition sources, including non-electrical ignition sources, are to be installed showing: (A) All major production equipment, wells, and other significant hydrocarbon sources, and a description of the type of decking, ceiling, walls (*e.g.,* grating or solid), and firewalls and; (B) The location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (*e.g.,* type cable, conduit, wire) and; (iii) One-line electrical drawings of all electrical systems including the safety shutdown system. You must also include a functional legend.
(4) Schematics of the fire and gas-detection systems	Showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; the method used for detection; and the method and frequency of calibration.
(5) The service fee listed in § 250.125	The fee you must pay will be determined by the number of components involved in the review and approval process.

(b) In the production safety system application, you must also certify the following:

(1) That all electrical installations were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference as specified in § 250.198);

(2) That the designs for the mechanical and electrical systems under paragraph (a) of this section were reviewed, approved, and stamped by an appropriate registered professional engineer(s). The registered professional engineer must be registered in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and

(3) That a hazards analysis was performed in accordance with § 250.1911 and API RP 14J (incorporated by reference as specified in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the facility.

(c) Before you begin production, you must certify, in a letter to the District Manager, that the mechanical and electrical systems were installed in accordance with the approved designs.

(d) Within 60 days after production commences, you must certify, in a letter to the District Manager, that the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1) and (2) of this section and the piping and instrumentation diagrams are on file and have been certified correct and stamped by an appropriate registered professional engineer(s). The registered professional engineer must be registered in a State or Territory in the United States and have sufficient expertise and experience to perform the duties.

(e) All as-built diagrams outlined in paragraphs (a)(1) and (2) of this section must be submitted to the District Manager within 60 days after production commences.

(f) You must maintain information concerning the approved designs and installation features of the production safety system at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. As-built piping and instrumentation diagrams must be maintained at a secure onshore location and readily available offshore. These documents must be made available to BSEE upon request and be retained for the life of the facility. All approvals are subject to field verifications.

§§ 250.843–250.849 [Reserved]

Additional Production System Requirements

§ 250.850 Production system requirements—general.

You must comply with the production safety system requirements in §§ 250.851 through 250.872, in addition to the practices contained in API RP 14C (incorporated by reference as specified in § 250.198).

§ 250.851 Pressure vessels (including heat exchangers) and fired vessels.

(a) Pressure vessels (including heat exchangers) and fired vessels supporting production operations must meet the requirements in the following table:

Item name	Applicable codes and requirements
(1) Pressure and fired vessels	(i) Must be designed, fabricated, and code stamped according to applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in § 250.198). (ii) Must be repaired, maintained, and inspected in accordance with API 510 (incorporated by reference as specified in § 250.198).
(2) Existing uncoded pressure and fired vessels (i) in use on November 7, 2016; (ii) with an operating pressure greater than 15 psig; and (iii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code.	Must be justified and approval obtained from the District Manager for their continued use after March 1, 2018.

Item name	Applicable codes and requirements
(3) Pressure relief valves	(i) Must be designed and installed according to applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in § 250.198). (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only). (iii) Vents must be positioned in such a way as to prevent fluid from striking personnel or ignition sources.
(4) Steam generators operating at less than 15 psig	Must be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level.
(5) Steam generators operating at 15 psig or greater	(i) Must be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. (ii) Must be equipped with a water-feeding device that will automatically control the water level except when closed loop systems are used for steam generation.

(b) *Operating pressure ranges.* You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time that the normalized system pressure changes by 50 psig or 5 percent. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the pressure recording information you used to determine current operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) High pressure shut-in sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the vessel.	Must also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut-in before the relief valve activates.
(2) Low pressure shut-in sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest pressure in the operating range.	You must receive specific approval from the District Manager for activation limits on pressure vessels that have a pressure safety low (PSL) sensor set less than 5 psi.

§ 250.852 Flowlines/Headers.

(a) You must:

(1) Equip flowlines from wells with both PSH and PSL sensors. You must locate these sensors in accordance with section A.1 of API RP 14C (incorporated by reference as specified in § 250.198).

(2) Use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long.

(3) Maintain the most recent pressure recording information you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(b) Flowline shut-in sensors must meet the requirements in the following table (initial set points for pressure sensors must be set using gauge readings and engineering design):

Type of flowline sensor	Settings
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the flowline. In all cases, the PSH must be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to ensure actuation of the SSV. Do not set the PSH sensor above the maximum allowable working pressure of the flowline.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the flowline in which it is installed.

(c) If a well flows directly to a pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. You must design the platform flare scrubber to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of hydrocarbons that may be relieved to the vessel; or

(2) Two SSVs with independent PSH sensors connected to separate relays and sensing points and installed with adequate volume upstream of any block valve to allow sufficient time for the SSVs to close before exceeding the maximum allowable working pressure. Each independent PSH sensor must close both SSVs along with any associated flowline PSL sensor. If the maximum shut-in pressure of a dry tree satellite well(s) is greater than 1½ times the maximum allowable pressure of the pipeline, a pressure safety valve (PSV) of sufficient size and relief capacity to protect against any SSV leakage or fluid hammer effect may be required by the District Manager. The PSV must be installed upstream of the host platform boarding valve and vent into the platform flare scrubber or some other location approved by the District Manager.

(d) If a well flows directly to the pipeline from a header without prior separation, the header, the header inlet valves, and pipeline isolation valve must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the header is protected by the safety devices as outlined in paragraph (c) of this section.

(e) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(1) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec. 17J (incorporated by reference as specified in § 250.198);

(2) Determine that the unbonded flexible pipe is suitable for its intended purpose;

(3) Submit to the District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(4) Submit to the District Manager a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of API Spec. 17J (incorporated by reference as specified in § 250.198).

(f) Automatic pressure or flow regulating choking devices must not prevent the normal functionality of the process safety system that includes, but is not limited to, the flowline pressure safety devices and the SSV.

(g) You may install a single flow safety valve (FSV) on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser provided that you install an FSV for each riser on the platform and test it in accordance with the criteria prescribed in § 250.880(c)(2)(v).

(h) You may install a single PSHL sensor on the platform to protect multiple subsea pipelines that tie into a single pipeline riser provided that you install a PSHL sensor for each riser on the platform and locate it upstream of the BSDV.

§ 250.853 Safety sensors.

You must ensure that:

(a) All shutdown devices, valves, and pressure sensors function in a manual reset mode;

(b) Sensors with integral automatic reset are equipped with an appropriate device to override the automatic reset mode; and

(c) All pressure sensors are equipped to permit testing with an external pressure source.

§ 250.854 Floating production units equipped with turrets and turret-mounted systems.

(a) For floating production units equipped with an auto slew system, you must integrate the auto slew control system with your process safety system allowing for automatic shut-in of the production process, including the sources (subsea wells, subsea pumps, *etc.*) and releasing of the buoy. Your safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839 and release the buoy to prevent hydrocarbon discharge and damage to the subsea infrastructure when the following are encountered:

(1) Your buoy is clamped,

(2) Your auto slew mode is activated, and

(3) You encounter a ship heading/position failure or an exceedance of the rotational tolerances of the clamped buoy.

(b) For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, your surface safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839.

§ 250.855 Emergency shutdown (ESD) system.

The ESD system must conform to the requirements of Appendix C, section C1, of API RP 14C (incorporated by reference as specified in § 250.198), and the following:

(a) The manually operated ESD valve(s) must be quick-opening and non-restricted to enable the rapid actuation of the shutdown system. Electronic ESD stations must be wired as de-energize to trip circuits or as supervised circuits. Because of the key role of the ESD system in the platform safety system, all ESD components must be of high quality and corrosion resistant and stations must be uniquely identified. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve or electric switch. This breakable loop is not required to be physically located on the boat landing, but must be accessible from a vessel adjacent to or attached to the facility.

(b) You must maintain a schematic of the ESD that indicates the control functions of all safety devices for the platforms on the platform, at your field office nearest the OCS facility, or at another location conveniently available to the District Manager, for the life of the facility.

§ 250.856 Engines.

(a) *Engine exhaust.* You must equip all engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2 (incorporated by reference as specified in § 250.198). You must equip exhaust piping from diesel engines with spark arresters.

(b) *Diesel engine air intake.* You must equip diesel engine air intakes with a device to shut down the diesel engine in the event of runaway (*i.e.,* overspeed). You must equip diesel engines that are continuously attended with either remotely operated manual or automatic shutdown devices. You must equip diesel engines that are not continuously attended with automatic shutdown devices. The following diesel engines do not require a shutdown device: Engines for fire water pumps;

engines on emergency generators; engines that power BOP accumulator systems; engines that power air supply for confined entry personnel; temporary equipment on non-producing platforms; booster engines whose purpose is to start larger engines; and engines that power portable single cylinder rig washers.

§ 250.857 Glycol dehydration units.

(a) You must install a pressure relief system or an adequate vent on the glycol regenerator (reboiler) to prevent over pressurization. The discharge of the relief valve must be vented in a nonhazardous manner.

(b) You must install the FSV on the dry glycol inlet to the glycol contact tower as near as practical to the glycol contact tower.

(c) You must install the shutdown valve (SDV) on the wet glycol outlet from the glycol contact tower as near as practical to the glycol contact tower.

§ 250.858 Gas compressors.

(a) You must equip compressor installations with the following protective equipment as required in API RP 14C, sections A.4 and A.8 (incorporated by reference as specified in § 250.198).

(1) A pressure safety high (PSH) sensor, a pressure safety low (PSL) sensor, a pressure safety valve (PSV), a level safety high (LSH) sensor, and a level safety low (LSL) sensor to protect each interstage and suction scrubber.

(2) A temperature safety high (TSH) sensor in the discharge piping of each compressor cylinder or case discharge.

(3) You must design the PSH and PSL sensors and LSH controls protecting compressor suction and interstage scrubbers to actuate automatic SDVs located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDVs installed in compressor suction and fuel gas piping must also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Manager, gas-well gas affected by the closure of the automatic SDV on the suction side of a compressor must be diverted to the pipeline, diverted to a flare or vent in accordance with §§ 250.1160 or 250.1161, or shut-in at the wellhead.

(4) You must install a blowdown valve on the discharge line of all compressor installations that are 1,000 horsepower (746 kilowatts) or greater.

(b) Once system pressure has stabilized, you must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors whenever the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line and sufficiently below the maximum discharge pressure to ensure actuation of the suction SDV.	Must also be set sufficiently below (5 percent or 5 psi, whichever is greater) the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed.	

§ 250.859 Firefighting systems.

(a) On fixed facilities, to protect all areas where production-handling equipment is located, you must install firefighting systems that meet the requirements of this paragraph. You must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors to protect all areas where production-handling equipment is located. Your firewater system must include installation of a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(1) Your firewater system must conform to API RP 14G (incorporated by reference as specified in § 250.198).

(2) Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this pump operating time unless the District Manager has approved an alternate firefighting system. In addition:

(i) As of September 7, 2017, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system.

(ii) For electric-driven firewater pump drivers, to provide for a potential loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment.

(iii) You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.

(3) You must post, in a prominent place on the facility, a diagram of the firefighting system showing the location of all firefighting equipment.

(4) For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions.

(5) You must obtain approval from the District Manager before installing any firefighting system.

(6) All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system.

(b) On floating facilities, to protect all areas where production-handling equipment is located, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Your firewater system must conform to the USCG requirements for firefighting systems on floating facilities.

(c) Except as provided in paragraph (c)(1) and (2) of this section, on fixed and floating facilities, if you are required to maintain a firewater system and the system becomes inoperable, you must shut-in your production operations while making the necessary repairs. For fixed facilities only, you may continue your production operations on a temporary basis while you make the necessary repairs, provided that:

(1) You request that the appropriate District Manager approve the use of a chemical firefighting system on a temporary basis (for a period up to 7 days) while you make the necessary repairs;

(2) If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the District Manager may grant multiple extensions to your previously approved request to use a chemical firefighting system for periods up to 7 days each.

§ 250.860 Chemical firefighting system.

For fixed platforms:

(a) On minor unmanned platforms, you may use a U.S. Coast Guard type and size rating ''B–II'' portable dry chemical unit (with a minimum UL Rating (US) of 60–B:C) or a 30-pound portable dry chemical unit, in lieu of a water system, as long as you ensure that the unit is available on the platform when personnel are on board.

(1) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(2) An unmanned platform is one that is not attended 24 hours a day or one on which personnel are not quartered overnight.

(b) On major platforms and minor manned platforms, you may use a firefighting system using chemicals-only in lieu of a water-based system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control and would not increase the risk to human safety.

(1) A major platform is a structure with either six or more completions or zero to five completions with more than one item of production processing equipment.

(2) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(3) A manned platform is one that is attended 24 hours a day or one on which personnel are quartered overnight.

(c) On major platforms and minor manned platforms, to obtain approval to use a chemical-only fire prevention and control system in lieu of a water system under paragraph (b) of this section, you must submit to the District Manager:

(1) A justification for asserting that the use of a chemical system provides equivalent fire-protection control. The justification must address fire prevention, fire protection, fire control, and firefighting on the platform; and

(2) A risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. You must provide the following and any other important information in your risk assessment:

For the use of a chemical fire-fighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
(i) Platform description	(A) The type and quantity of hydrocarbons (*i.e.,* natural gas, oil) that are produced, handled, stored, or processed at the facility. (B) The capacity of any tanks on the facility that you use to store either liquid hydrocarbons or other flammable liquids. (C) The total volume of flammable liquids (other than produced hydrocarbons) stored on the facility in containers other than bulk storage tanks. Include flammable liquids stored in paint lockers, storerooms, and drums. (D) If the facility is manned, provide the maximum number of personnel on board and the anticipated length of their stay. (E) If the facility is unmanned, provide the number of days per week the facility will be visited, the average length of time spent on the facility per visit, the mode of transportation, and whether or not transportation will be available at the facility while personnel are on board. (F) A diagram that depicts: quarters location, production equipment location, fire prevention and control equipment location, lifesaving appliances and equipment location, and evacuation plan escape routes from quarters and all manned working spaces to primary evacuation equipment.
(ii) Hazard assessment (facility specific).	(A) Identification of all likely fire initiation scenarios (including those resulting from maintenance and repair activities). For each scenario, discuss its potential severity and identify the ignition and fuel sources. (B) Estimates of the fire/radiant heat exposure that personnel could be subjected to. Show how you have considered designated muster areas and evacuation routes near fuel sources and have verified proper flare boom sizing for radiant heat exposure.
(iii) Human factors assessment (not facility specific).	(A) Descriptions of the fire-related training your employees and contractors have received. Include details on the length of training, whether the training was hands-on or classroom, the training frequency, and the topics covered during the training. (B) Descriptions of the training your employees and contractors have received in fire prevention, control of ignition sources, and control of fuel sources when the facility is occupied. (C) Descriptions of the instructions and procedures you have given to your employees and contractors on the actions they should take if a fire occurs. Include those instructions and procedures specific to evacuation. State how you convey this information to your employees and contractors on the platform.
(iv) Evacuation assessment (facility specific).	(A) A general discussion of your evacuation plan. Identify your muster areas (if applicable), both the primary and secondary evacuation routes, and the means of evacuation for both. (B) Description of the type, quantity, and location of lifesaving appliances available on the facility. Show how you have ensured that lifesaving appliances are located in the near vicinity of the escape routes. (C) Description of the types and availability of support vessels, whether the support vessels are equipped with a fire monitor, and the time needed for support vessels to arrive at the facility. (D) Estimates of the worst case time needed for personnel to evacuate the facility should a fire occur.
(v) Alternative protection assessment.	(A) Discussion of the reasons you are proposing to use an alternative fire prevention and control system.

For the use of a chemical fire-fighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
	(B) Lists of the specific standards used to design the system, locate the equipment, and operate the equipment/system. (C) Description of the proposed alternative fire prevention and control system/equipment. Provide details on the type, size, number, and location of the prevention and control equipment. (D) Description of the testing, inspection, and maintenance program you will use to maintain the fire prevention and control equipment in an operable condition. Provide specifics regarding the type of inspection, the personnel who conduct the inspections, the inspection procedures, and documentation and recordkeeping.
(vi) Conclusion	A summary of your technical evaluation showing that the alternative system provides an equivalent level of personnel protection for the specific hazards located on the facility.

(d) On major or minor platforms, if BSEE has approved your request to use a chemical-only fire suppressant system in lieu of a water system under paragraphs (b) and (c) of this section, and if you make an insignificant change to your platform subsequent to that approval, you must document the change and maintain the documentation for the life of the facility at either the facility or nearest field office for BSEE review and/or inspection. Do not submit this documentation to the District Manager. However, if you make a significant change to your platform (*e.g.,* placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment), or if you plan to man an unmanned platform temporarily, you must submit a new request for approval, including an updated risk assessment if previously required, to the appropriate District Manager. You must maintain, for the life of the facility, the most recent documentation that you submitted to BSEE at the facility or nearest field office.

§ 250.861 Foam firefighting systems.

When you install foam firefighting systems as part of a firefighting system that protects production handling areas, you must:

(a) Annually conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration;

(b) Annually send samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing. You must have the sample tested to determine the specific gravity, pH, percentage of water dilution, and solid content. Based on these results, the foam must be certified by an authorized representative of the manufacturer as suitable firefighting foam consistent with the original manufacturer's specifications. The certification document must be readily accessible for field inspection. In lieu of sampling and certification, you may choose to replace the total inventory of foam with suitable new stock;

(c) Ensure that the quantity of concentrate meets design requirements, and that tanks or containers are kept full, with space allowed for expansion.

§ 250.862 Fire and gas-detection systems.

For production processing areas only:

(a) You must install fire (flame, heat, or smoke) sensors in all enclosed classified areas. You must install gas sensors in all inadequately ventilated, enclosed classified areas.

(1) Adequate ventilation is defined as ventilation that is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit. An acceptable method of providing adequate ventilation is one that provides a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater.

(2) Enclosed areas (*e.g.,* buildings, living quarters, or doghouses) are defined as those areas confined on more than 4 of their 6 possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to allow entry of personnel.

(3) A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500 (incorporated by reference as specified in § 250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (incorporated by reference as specified in § 250.198).

(b) All detection systems must be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas-concentration levels must be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(c) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. A gas detection system is not required for living quarters and doghouses that do not contain a gas source and that are not located in a classified area.

(d) The District Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(e) Fire- and gas-detection systems must be an approved type, and designed and installed in accordance with API RP 14C, API RP 14G, API RP 14F, API RP 14FZ, API RP 500, and API RP 505 (all incorporated by reference as specified in § 250.198), provided that, if compliance with any provision of those standards would be in conflict with applicable regulations of the U.S. Coast Guard, compliance with the U.S. Coast Guard regulations controls.

§ 250.863 Electrical equipment.

You must design, install, and maintain electrical equipment and systems in accordance with the requirements in § 250.114.

§ 250.864 Erosion.

You must have a program of erosion control in effect for wells or fields that have a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. You must maintain records for each lease that indicate the wells that have erosion-control programs in effect. You must also maintain the results of the programs for at least 2 years and make them available to BSEE upon request.

§ 250.865 Surface pumps.

(a) You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—A.7, Pumps (incorporated by reference as specified in § 250.198).

(b) You must use pressure recording devices to establish the new operating pressure ranges for pump discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must only maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor	Must be no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line.	Must be set sufficiently below the maximum allowable working pressure of the discharge piping. The PSH must also be set at least 5 percent or 5 psi (whichever is greater) below the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed.	

(d) The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner.

(e) You may exclude the PSH and PSL sensors on small, low-volume pumps such as chemical injection-type pumps. This is acceptable if such a pump is used as a sump pump or transfer pump, has a discharge rating of less than ½ gallon per minute (gpm), discharges into piping that is 1 inch or less in diameter, and terminates in piping that is 2 inches or larger in diameter.

(f) You must install a TSE in the immediate vicinity of all pumps in hydrocarbon service or those powered by platform fuel gas.

(g) The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver as appropriate for the pump type and service.

§ 250.866 Personnel safety equipment.

You must maintain all personnel safety equipment located on a facility, whether required or not, in good working condition.

§ 250.867 Temporary quarters and temporary equipment.

(a) The District Manager must approve all temporary quarters to be installed in production processing areas or other classified areas on OCS facilities. You must equip such temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198).

(b) The District Manager may require you to install a temporary firewater system for temporary quarters in production processing areas or other classified areas.

(c) Temporary equipment associated with the production process system, including equipment used for well testing and/or well clean-up, must be approved by the District Manager.

§ 250.868 Non-metallic piping.

On fixed OCS facilities, you may use non-metallic piping (such as that made from polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass) only in accordance with the requirements of § 250.841(b).

§ 250.869 General platform operations.

(a) Surface or subsurface safety devices must not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing. You may take only the minimum number of safety devices out of service. Personnel must monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service must be flagged. A designated visual indicator must be used to identify the bypassed safety device. You must follow the monitoring procedures as follows:

(1) If you are using a non-computer-based system, meaning your safety system operates primarily with pneumatic supply or non-programmable electrical systems, you must monitor bypassed safety devices by positioning monitoring personnel at either the control panel for the bypassed safety device, or at the bypassed safety device, or at the component that the bypassed safety device would be monitoring when in service. You must also ensure that monitoring personnel are able to view all relevant essential operating conditions until all bypassed safety devices are placed back in service and are able to initiate shut-in action in the event of an abnormal condition.

(2) If you are using a computer-based technology system, meaning a computer-controlled electronic safety system such as supervisory control and data acquisition and remote terminal units, you must monitor bypassed safety devices by maintaining instantaneous communications at all times among remote monitoring personnel and the personnel performing maintenance, testing, or startup. Until all bypassed safety devices are placed back in service, you must also position monitoring personnel at a designated control station that is capable of the following:

(i) Displaying all relevant essential operating conditions that affect the bypassed safety device, well, pipeline, and process component. If electronic display of all relevant essential conditions is not possible, you must have field personnel monitoring the level gauges (sight glass) and pressure gauges in order to know the current operating conditions. You must be in communication with all field personnel monitoring the gauges;

(ii) Controlling the production process equipment and the entire safety system;

(iii) Displaying a visual indicator when safety devices are placed in the bypassed mode; and

(iv) Upon command, overriding the bypassed safety device and initiating shut-in action in the event of an abnormal condition.

(3) You must not bypass for startup any element of the emergency support system or other support system required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198) without first receiving BSEE approval to depart from this

operating procedure. These systems include, but are not limited to:

(i) The ESD system to provide a method to manually initiate platform shutdown by personnel observing abnormal conditions or undesirable events. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(ii) The fire loop system to sense the heat of a fire and initiate platform shutdown, and other fire detection devices (flame, thermal, and smoke) that are used to enhance fire detection capability. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(iii) The combustible gas detection system to sense the presence of hydrocarbons and initiate alarms and platform shutdown before gas concentrations reach the lower explosive limit;

(iv) Adequate ventilation;

(v) The containment system to collect escaped liquid hydrocarbons and initiate platform shutdown;

(vi) Subsurface safety valves, including those that are self-actuated (subsurface-controlled SSSVs) or those that are activated by an ESD system and/or a fire loop (surface-controlled SSSV). You do not have to receive approval from the District Manager for routine operations in accordance with § 250.817;

(vii) The pneumatic supply system; and

(viii) The system for discharging gas to the atmosphere.

(4) In instances where components of the ESD, as listed in paragraph (a)(3) of this section, are bypassed for maintenance, precautions must be taken to provide the equivalent level of protection that existed prior to the bypass.

(b) When wells are disconnected from producing facilities and blind flanged, or equipped with a tubing plug, or the master valves have been locked closed, you are not required to comply with the provisions of API RP 14C (incorporated by reference as specified in § 250.198) or this regulation concerning the following:

(1) Automatic fail-close SSVs on wellhead assemblies, and

(2) The PSH and PSL sensors in flowlines from wells.

(c) When pressure or atmospheric vessels are isolated from production facilities (*e.g.,* inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device testing in accordance with API RP 14C (incorporated by reference as specified in § 250.198), or this subpart is not required, with the exception of the PSV, unless the vessel is open to the atmosphere.

(d) All open-ended lines connected to producing facilities and wells must be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(e) On all new production safety system installations, component process control devices and component safety devices must not be installed utilizing the same sensing points.

(f) All pneumatic control panels and computer based control stations must be labeled according to API RP 14C nomenclature.

§ 250.870 Time delays on pressure safety low (PSL) sensors.

(a) You may apply any or all of the industry standard Class B, Class C, or Class B/C logic to all applicable PSL sensors installed on process equipment, as long as the time delay does not exceed 45 seconds. Use of a PSL sensor with a time delay greater than 45 seconds requires BSEE approval in accordance with § 250.141. You must document on your field test records any use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:

(1) Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). Examples include sensors used in conjunction with the design of pump and compressor panels such as PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns.

(2) Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.,* the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure, and the PSL sensor clears).

(3) Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during startup and idle operations, (*e.g.,* Class B/C bypass circuitry activates when a pump is shut down during normal operations). The PSL sensor remains bypassed until the pump's start circuitry is activated and either:

(i) The Class B timer expires no later than 45 seconds from start activation, or

(ii) The Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.

(b) If you do not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, you must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds.

§ 250.871 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities must be conducted according to the specific requirements in § 250.113.

§ 250.872 Atmospheric vessels.

(a) You must equip atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids as described in API RP 500 or 505 (both incorporated by reference as specified in § 250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference as specified in § 250.198). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage of refined liquid hydrocarbons or Class I liquids, are not required to be equipped with the protective equipment identified in API RP 14C, section A.5.

(b) You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.

(c) You must ensure that all flame arrestors are maintained to ensure proper design function (installation of a system to allow for ease of inspection should be considered).

§ 250.873 Subsea gas lift requirements.

If you choose to install a subsea gas lift system, you must design your system as approved in your DWOP or as follows:

(a) Design the gas lift supply pipeline in accordance with API RP 14C (incorporated by reference as specified in § 250.198) for the gas lift supply system located on the platform.

(b) Meet the applicable requirements in the following table:

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(1) Subsea pipelines, pipeline risers, or manifolds via an external gas lift pipeline or umbilical.	Meet all of the requirements for the BSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (in-board) of the GLSDV.	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. (iii) Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).
(2) Subsea well(s) through the casing string via an external gas lift pipeline or umbilical.	Meet all of the requirements for the GLSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (in-board) of the GLSDV.	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated..	(i) Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. (ii) If your subsea tree or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. (iii) Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.
(3) Pipeline risers via a gas-lift line contained within the pipeline riser.	Meet all of the requirements for the GLSDV described in §§ 250.835(a), (b), and (d) and 250.836 on the gas-lift supply pipeline. Attach the GLSDV by flanged connection directly to the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser.	upstream (in-board) of the GLSDV.	flowline upstream (in-board) of the FSV.	downstream (out board) of the GLSDV.	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser. (ii) Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (iii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iv) Suspend and seal the gas-lift flowline contained within the production riser in a flanged API Spec. 6A component such as an API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of API Spec. 6A. (v) Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. (vi) Ensure that this complete assembly is fire-rated for 30 minutes.

(c) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with gas lift,

(2) Electro-hydraulic control system with gas lift with loss of communications,

(3) Direct-hydraulic control system with gas lift.

(d) Follow the gas lift system valve testing requirements according to the following table:

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
(1) Gas lifting a subsea pipeline, pipeline riser, or manifold via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
	GLIV	N/A	Function tested quarterly, not to exceed 120 days.
(2) Gas lifting a subsea well through the casing string via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	400 cc per minute of liquid or 15 scf per minute of gas..	Function tested quarterly, not to exceed 120 days
(3) Gas lifting the pipeline riser via a gas lift line contained within the pipeline riser.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

§ 250.874 Subsea water injection systems.

If you choose to install a subsea water injection system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Adhere to the water injection requirements described in API RP 14C (incorporated by reference as specified in § 250.198) for the water injection equipment located on the platform. In accordance with § 250.830, either a surface-controlled SSSV or a water injection valve (WIV) that is self-activated and not controlled by emergency shut-down (ESD) or sensor activation must be installed in a subsea water injection well.

(b) Equip a water injection pipeline with a surface FSV and water injection shutdown valve (WISDV) on the surface facility.

(c) Install a PSHL sensor upstream (in-board) of the FSV and WISDV.

(d) Use subsea tree(s), wellhead(s), connector(s), and tree valves, and surface-controlled SSSV or WIV associated with a water injection system that are rated for the maximum anticipated injection pressure.

(e) Consider the effects of hydrogen sulfide (H2S) when designing your water flood system, as required by § 250.805.

(f) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with water injection,

(2) Electro-hydraulic control system with water injection with loss of communications, and

(3) Direct-hydraulic control system with water injection.

(g) Comply with the following injection valve testing requirements:

(1) You must test your injection valves as provided in the following table:

Valve	Allowable leakage rate	Testing frequency
(i) WISDV	Zero leakage	Monthly, not to exceed 6 weeks between tests.
(ii) Surface-controlled SSSV or WIV	400 cc per minute of liquid or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months between tests.

(2) If a designated USV on a water injection well fails the applicable test under § 250.880(c)(4)(ii), you must notify the appropriate District Manager and request approval to designate another API Spec 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198) certified subsea valve as your USV.

(3) If a USV on a water injection well fails the test and the surface-controlled SSSV or WIV cannot be tested as required under (g)(1)(ii) of this section because of low reservoir pressure, you must submit a request to the appropriate District Manager with an alternative plan that ensures subsea shutdown capabilities.

(h) If you experience a loss of communications during water injection operations, you must comply with the following:

(1) Notify the appropriate District Manager within 12 hours after detecting loss of communication; and

(2) Obtain approval from the appropriate District Manager to continue to inject during the loss of communication.

§ 250.875 Subsea pump systems.

If you choose to install a subsea pump system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Include the installation of an isolation valve at the inlet of your subsea pump module.

(b) Include a PSHL sensor upstream of the BSDV, if the maximum possible discharge pressure of the subsea pump operating in a dead head condition (that is the maximum shut-in tubing pressure at the pump inlet and a closed BSDV) is less than the MAOP of the associated pipeline.

(c) If the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the MAOP of the pipeline:

(1) Include, at minimum, 2 independent functioning PSHL sensors upstream of the subsea pump and 2 independent functioning PSHL sensors downstream of the pump, that:

(i) Are operational when the subsea pump is in service; and

(ii) Will, when activated, shut down the subsea pump, the subsea inlet isolation valve, and either the designated USV1, the USV2, or the alternate isolation valve.

(iii) If more than 2 PSHL sensors are installed both upstream and downstream of the subsea pump for operational flexibility, then 2 out of 3 voting logic may be implemented in which the subsea pump remains operational provided a minimum of 2 independent PSHL sensors are functional both upstream and downstream of the pump.

(2) Interlock the subsea pump motor with the BSDV to ensure that the pump cannot start or operate when the BSDV is closed, incorporate at a minimum the following permissive signals into the control system for your subsea pump, and ensure that the subsea pump is not able to be started or re-started unless:

(i) The BSDV is open;

(ii) All automated valves downstream of the subsea pump are open;

(iii) The upstream subsea pump isolation valve is open; and

(iv) All parameters associated with the subsea pump operation (*e.g.,* pump temperature high, pump vibration high, pump suction pressure high, pump discharge pressure high, pump suction flow low) must be cleared (*i.e.,* within operational limits) or continuously monitored by personnel who observe visual indicators displayed at a designated control station and have the capability to initiate shut-in action in the event of an abnormal condition.

(3) Monitor the separator for seawater.

(4) Ensure that the subsea pump systems are controlled by an electro-hydraulic control system.

(d) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with a subsea pump;

(2) A loss of communication with the subsea well(s) and not a loss of communication with the subsea pump control system without an ESD or sensor activation;

(3) A loss of communication with the subsea pump control system, and not a loss of communication with the subsea well(s);

(4) A loss of communication with the subsea well(s) and the subsea pump control system.

(e) For subsea pump testing:

(1) Perform a complete subsea pump function test, including full shutdown, after any intervention or changes to the software and equipment affecting the subsea pump; and

(2) Test the subsea pump shutdown, including PSHL sensors both upstream and downstream of the pump, each quarter (not to exceed 120 days between tests). This testing may be performed concurrently with the ESD function test required by § 250.880(c)(4)(v).

§ 250.876 Fired and exhaust heated components.

No later than September 7, 2018, and at least once every 5 years thereafter, you must have a qualified third-party remove and inspect, and then you must repair or replace, as needed, the fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If removal and inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make the documentation available to BSEE upon request.

§§ 250.877—250.879 [Reserved]

Safety Device Testing

§ 250.880 Production safety system testing.

(a) *Notification.* You must:

(1) Notify the District Manager at least 72 hours before commencing production, so that BSEE may conduct a preproduction inspection of the integrated safety system.

(2) Notify the District Manager upon commencement of production so that BSEE may conduct a complete inspection.

(3) Notify the District Manager and receive BSEE approval before you perform any subsea intervention that modifies the existing subsea infrastructure in a way that may affect the casing monitoring capabilities and testing frequencies specified in the table set forth in paragraph (c)(4) of this section.

(b) *Testing methodologies.* You must:

(1) Test safety valves and other equipment at the intervals specified in the tables set forth in paragraph (c) of this section or more frequently if operating conditions warrant; and

(2) Perform testing and inspections in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198), and the additional requirements specified in the tables of this section or as approved in the DWOP for your subsea system.

(c) *Testing frequencies.* You must:

(1) Comply with the following testing requirements for subsurface safety devices on dry tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells.	Semi-annually, not to exceed 6 calendar months between tests. Also test in place when first installed or reinstalled. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to API RP 14B (incorporated by reference as specified in § 250.198) to ensure proper operation.
(ii) Subsurface-controlled SSSVs	Semi-annually, not to exceed 6 calendar months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple. The valve must be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced.
(iii) Tubing plug	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the plug must be removed, repaired, and reinstalled or replaced. An additional tubing plug may be installed in lieu of removal.
(iv) Injection valves	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired and reinstalled or replaced.

(2) Comply with the following testing requirements for surface valves:

Item name	Testing frequency and requirements
(i) PSVs	Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing. The main valve piston must be lifted during this test.

Item name	Testing frequency and requirements
(ii) Automatic inlet SDVs that are actuated by a sensor on a vessel or compressor.	Once each calendar month, not to exceed 6 weeks between tests.
(iii) SDVs in liquid discharge lines and actuated by vessel low-level sensors.	Once each calendar month, not to exceed 6 weeks between tests.
(iv) SSVs	Once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API RP 14H (incorporated by reference as specified in § 250.198). If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(v) Flowline FSVs	Once each calendar month, not to exceed 6 weeks between tests. All flowline FSVs must be tested, including those installed on a host facility in lieu of being installed at a satellite well. You must test flowline FSVs for leakage in accordance with the test procedure specified in API RP 14C (incorporated by reference as specified in § 250.198). If leakage measured exceeds a liquid flow of 400 cubic centimeters per minute or a gas flow of 15 standard cubic feet per minute, the FSV must be repaired or replaced.

(3) Comply with the following testing requirements for surface safety systems and devices:

Item name	Testing frequency and requirements
(i) Pumps for firewater systems	Must be inspected and operated according to API RP 14G, Section 7.2 (incorporated by reference as specified in § 250.198).
(ii) Fire- (flame, heat, or smoke) and gas detection systems.	Must be tested for operation and recalibrated every 3 months, not to exceed 120 days between tests, provided that testing can be performed in a non-destructive manner. Open flame or devices operating at temperatures that could ignite a methane-air mixture must not be used. All combustible gas-detection systems must be calibrated every 3 months.
(iii) ESD systems	(A) Pneumatic based ESD systems must be tested for operation at least once each calendar month, not to exceed 6 weeks between tests. You must conduct the test by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once each calendar month, not to exceed 6 weeks between tests. No station may be reused until all stations have been tested. (B) Electronic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been tested. (C) Electronic/pneumatic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been used.
(iv) TSH devices	Must be tested for operation annually, not to exceed 12 calendar months between tests, excluding those addressed in paragraph (c)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.
(v) TSH shutdown controls installed on compressor installations that can be nondestructively tested.	Must be tested every 6 months and repaired or replaced as necessary.
(vi) Burner safety low	Must be tested annually, not to exceed 12 calendar months between tests.
(vii) Flow safety low devices	Must be tested annually, not to exceed 12 calendar months between tests.
(viii) Flame, spark, and detonation arrestors	Must be visually inspected annually, not to exceed 12 calendar months between inspections.
(ix) Electronic pressure transmitters and level sensors: PSH and PSL; LSH and LSL.	Must be tested at least once every 3 months, not to exceed 120 days between tests.
(x) Pneumatic/electronic switch PSH and PSL; pneumatic/electronic switch/electric analog with mechanical linkage LSH and LSL controls.	Must be tested at least once each calendar month, not to exceed 6 weeks between tests.

(4) Comply with the following testing requirements for subsurface safety devices and associated systems on subsea tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Tested semiannually, not to exceed 6 months between tests. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to API RP 14B (incorporated by reference as specified in § 250.198) to ensure proper operation, or as approved in your DWOP.
(ii) USVs	Tested at least once every 3 calendar months, not to exceed 120 days between tests. If the device does not function properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired, and reinstalled or replaced.
(iii) BSDVs	Tested at least once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API RP 14H for SSVs (incorporated by reference as specified in § 250.198). If a BSDV does not operate properly or if any fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(iv) Electronic ESD logic	Tested at least once each calendar month, not to exceed 6 weeks between tests.
(v) Electronic ESD function	Tested at least once every 3 calendar months, not to exceed 120 days between tests. Shut-in at least one well during the ESD function test. If multiple wells are tied back to the same platform, a different well should be shut-in with each quarterly test.

(d) *Subsea wells.* (1) Any subsea well that is completed and disconnected from monitoring capability may not be disconnected for more than 24 months, unless authorized by BSEE.

(2) Any subsea well that is completed and disconnected from monitoring capability for more than 6 months must meet the following testing and other requirements:

(i) Each well must have 3 pressure barriers:

(A) A closed and tested surface-controlled SSSV,

(B) A closed and tested USV, and

(C) One additional closed and tested tree valve.

(ii) For new completed wells, prior to the rig leaving the well, the pressure barriers must be tested as follows:

(A) The surface-controlled SSSV must be tested for leakage in accordance with § 250.828(c);

(B) The USV and other pressure barrier must be tested to confirm zero leakage rate.

(iii) A sealing pressure cap must be installed on the flowline connection hub until the flowline is installed and connected. The pressure cap must be designed to accommodate monitoring for pressure between the production wing valve and cap. The pressure cap must also be designed so that a remotely operated vehicle can bleed pressure off, monitor for buildup, and confirm barrier integrity.

(iv) Pressure monitoring at the sealing pressure cap on the flowline connection hub must be performed in each well at intervals not to exceed 12 months from the time of initial testing of the pressure barrier (prior to demobilizing the rig from the field).

(v) You must have a drilling vessel capable of intervention into the disconnected well in the field or readily accessible for use until the wells are brought on line.

§§ 250.881—250.889 [Reserved]

Records and Training

§ 250.890 Records.

(a) You must maintain records that show the present status and history of each safety device. Your records must include dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

(b) You must maintain these records for at least 2 years. You must maintain the records at your field office nearest the OCS facility and a secure onshore location. These records must be available for review by a representative of BSEE.

(c) You must submit to the appropriate District Manager a contact list for all OCS facilities at least annually or when contact information is revised. The contact list must include:

(1) Designated operator name;

(2) Designated primary point of contact for the facility;

(3) Facility phone number(s), if applicable;

(4) Facility fax number, if applicable;

(5) Facility radio frequency, if applicable;

(6) Facility helideck rating and size, if applicable; and

(7) Facility records location if not contained on the facility.

§ 250.891 Safety device training.

You must ensure that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices, and personnel operating production platforms (including, but not limited to, separation, dehydration, compression, sweetening, and metering operations), are trained in accordance with the procedures in subpart O and subpart S of this part.

§§ 250.892–250.899 [Reserved]

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