DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Parts 250, 254, and 550

Bureau of Ocean Energy Management

30 CFR Part 550

[Docket ID: BSEE–2013–0011; 16XE1700DX EX1SF0000.DAQ000 EEEE500000]

RIN 1082–AA00

Oil and Gas and Sulfur Operations on the Outer Continental Shelf—Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE); Bureau of Ocean Energy Management (BOEM), Interior.

ACTION: Final rule.

SUMMARY: The Department of the Interior (DOI or the Department), acting through BOEM and BSEE, is revising and adding new requirements to regulations for exploratory drilling and related operations on the Outer Continental Shelf (OCS) seaward of the State of Alaska. This final rule focuses solely on the OCS within the Beaufort Sea and Chukchi Sea Planning Areas (Arctic OCS). The Arctic region is characterized by extreme environmental conditions, geographic remoteness, and a relative lack of fixed infrastructure and existing operations. This final rule is designed to help ensure the safe, effective, and responsible exploration of Arctic OCS oil and gas resources, while protecting the marine, coastal, and human environments, and Alaska Natives' cultural traditions and access to subsistence resources.

DATES: This rule becomes effective on September 13, 2016.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of September 13, 2016.

ADDRESSES: Comments and material received from the public, as well as documents mentioned in this preamble as being available in the docket, are part of docket BSEE–2013–0011 and are available for inspection or copying at the Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. You may also find this docket on the Internet by going to *http://www.regulations.gov,* and searching for BSEE–2013–0011.

Materials incorporated by reference in this final rule may be inspected by appointment at BOEM and BSEE Headquarters, 45600 Woodland Road, Sterling, Virginia 20166, or at the BOEM and BSEE Alaska Regional Offices, 3801 Centerpoint Drive, Suite 400 or Suite 500, Anchorage, Alaska 99503, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. To make an appointment, call (202) 258–1518.

FOR FURTHER INFORMATION CONTACT: Mark E. Fesmire, BSEE, Alaska Regional Office, *mark.fesmire@bsee.gov,* (907) 334–5300; John Caplis, BSEE, Oil Spill Preparedness Division, *john.caplis@bsee.gov,* (703) 787–1364; or David Johnston, BOEM, Alaska Regional Office, *david.johnston@boem.gov,* (907) 334–5200. To see a copy of any relevant information collection request submitted to Office of Management and Budget (OMB), go to *http://www.reginfo.gov* (select Information Collection Review).

SUPPLEMENTARY INFORMATION:

Executive Summary

Although there is currently a comprehensive OCS oil and gas regulatory program, there is a need for new and revised Arctic-specific regulatory measures for exploratory drilling conducted by floating drilling vessels and ''jack-up rigs'' (collectively known as mobile offshore drilling units or (MODU)) in the Beaufort Sea and Chukchi Sea Planning Areas (defined in this final rule as the Arctic OCS). The United States (U.S.) Arctic region, as recognized and defined in the U.S. Arctic Research and Policy Act of 1984, as amended, encompasses an extensive marine and terrestrial area; however, this final rule focuses solely on the OCS within the Beaufort Sea and Chukchi Sea Planning Areas.

On February 24, 2015, BOEM and BSEE published a Notice of Proposed Rulemaking (NPRM) in the **Federal Register** entitled, ''Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf'' (80 FR 9916). We received 1,311 letters to the docket, from over 100,000 individual commenters on the NPRM. Additionally, BOEM and BSEE engaged in Government-to-Government Tribal consultations and Government-to-Alaska Native Claims Settlement Act (ANCSA) Corporations consultations prior to and after publication of the NPRM, to discuss the subject matter of the proposed rule and to solicit input on the development of the final rule. In the development of the NPRM and this final rule, BOEM and BSEE undertook extensive environmental and safety reviews of potential oil and gas operations on the Arctic OCS. After considering comments on the NPRM, Tribal and other consultations, the environmental analysis, and DOI's direct experience from Shell's 2012 and 2015 Arctic operations, BOEM and BSEE concluded that finalizing additional exploratory drilling regulations will enhance existing regulations and is appropriate for establishing a more holistic Arctic OCS oil and gas regulatory framework.

The U.S Arctic region is known for its oil and gas resource potential, its vibrant ecosystems, and the Alaska Native communities, which rely on the Arctic's resources for subsistence use and cultural traditions. The region is characterized by extreme environmental conditions, geographic remoteness, and a relative lack of fixed infrastructure and existing operations. These are key factors in considering the feasibility, practicality, and safety of conducting offshore oil and gas activities on the Arctic OCS. This final rule will help to ensure that Arctic OCS exploratory drilling operations are conducted in a safe and responsible manner while taking into account the unique conditions of Arctic OCS drilling activities and Alaska Natives' cultural traditions and access to subsistence resources.

This final rule adds to and revises existing regulations in 30 CFR parts 250, 254, and 550 for Arctic OCS oil and gas activities and focuses on exploratory drilling activities that use MODUs and related operations during the Arctic OCS open-water drilling season. The final rule does not preclude exploratory drilling on the Arctic OCS conducted in the future using other drilling technologies (*e.g.,* use of a land rig on grounded or land-fast ice). Exploratory drilling operations using technologies other than MODUs are outside the scope of the final rule and would be evaluated under the existing OCS oil and gas regulatory program, as may be amended. The final regulations address a number of important issues and objectives, including ensuring that each operator:

1. Designs and conducts exploration programs in a manner that accounts for Arctic OCS conditions;

2. Develops an integrated operations plan (IOP) that addresses all phases of its proposed Arctic OCS exploration program, and submits the IOP to BOEM at least 90 days in advance of filing its Exploration Plan (EP);

3. Has access to, and the ability to promptly deploy, Source Control and Containment Equipment (SCCE) while drilling below, or working below, the surface casing;

4. Has access to a separate relief rig located in a geographic position to be able to timely drill a relief well under the conditions expected at the site in the event of a loss of well control;

5. Has the capability to predict, track, report, and respond to ice conditions and adverse weather events;

6. Effectively manages and oversees contractors; and,

7. Develops and implements an Oil Spill Response Plan (OSRP) that is designed and executed in a manner that accounts for the unique Arctic OCS operating environment, and has the necessary equipment, training, and personnel for oil spill response on the Arctic OCS.

The final rule furthers the Nation's stewardship of the Arctic's environment and resources, and establishes specific operating models and requirements for the extreme, changing conditions that exist on the Arctic OCS. The regulations will require comprehensive planning of operations, especially for emergency response and safety systems. A goal of the final rule is to encourage the identification of operational risks early in the planning process and to encourage operators to plan for how to avoid and/or mitigate those risks. The requirements in the final rule also aim to ensure that plans meet the challenges presented by Arctic conditions and are executed in a safe and environmentally protective manner.

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LIST OF ACRONYMS AND REFERENCES

60-Day Report	Report to the Secretary of the Interior, Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program.
ACPs	Area Contingency Plans.
AEWC	Alaska Eskimo Whaling Commission.
ANCSA	Alaska Native Claims Settlement Act.
APD	Application for Permit to Drill.
API	American Petroleum Institute.
APM	Application for Permit to Modify.
Arctic OCS	OCS within the Beaufort Sea and Chukchi Sea Planning Areas.
BAST	Best Available and Safest Technology.
BOEM	Bureau of.
BOP	Blowout Preventer.
BSEE	Bureau of Safety and Environmental Enforcement.
CAA	Conflict Avoidance Agreement.
CAP	Corrective Action Plan.
CFR	Code of Federal Regulations.
COCP	Critical Operations and Curtailment Plan.
CWA	Clean Water Act.
Department	Department of the Interior.
DOCD	Development Operations Coordination Document.
DOI	Department of the Interior.
DPP	Development and Production Plan.
EA	Environmental Assessment.
E.O.	Executive Order.
E.O. 13580 Alaska Energy Permitting IWG.	Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska.
EP	Exploration Plan.
EPA	Environmental Protection Agency.
ESA	Endangered Species Act.
FOSC	Federal On Scene Coordinator.
HPHT	High Pressure High Temperature.
IACS	International Association of Classification Societies.
IBR	Incorporation by Reference.
IC	Information Collection.

LIST OF ACRONYMS AND REFERENCES—Continued

ICAS	Inupiat Community of the Arctic Slope.
ICS	Incident Command System.
IEC	International Electrotechnical Commission.
IMH	Incident Management Handbook.
IMO	International Maritime Organization.
IMP	Ice Management Plan.
INC	Incident of Noncompliance.
IOGP	International Association of Oil and Gas Producers.
IOP	Integrated Operations Plan.
IPD	Interim Policy Document.
IPIECA	International Petroleum Industry Environmental Conservation Association.
IQA	Information Quality Act.
IRFA	Initial Regulatory Flexibility Analysis.
ISO	International Organization of Standardization.
MMPA	Marine Mammal Protection Act.
MMS	Minerals Management Service.
MOA	Memorandum of Agreement.
MODU	Mobile Offshore Drilling Unit.
MPD	Managed Pressure Drilling.
MWD	Measurement while Drilling.
NAICS	North American Industry Classification System.
NARA	National Archives and Records Administration.
NCP	National Oil and Hazardous Substances Pollution Contingency Plan.
NEPA	National Environmental Policy Act of 1969.
NMFS	National Marine Fisheries Service.
NOAA	National Oceanic and Atmospheric Administration.
NPC	National Petroleum Council.
NPDES	National Pollutant Discharge Elimination System.
NPRM	Notice of Proposed Rulemaking.
NSAR	President's National Strategy of the Arctic Region, issued May 2013.
NTL	Notice to Lessees and Operators.
NWS	National Weather Service.
OCS	Outer Continental Shelf.
OCSLA	Outer Continental Shelf Lands Act.
ODCE	Ocean Discharge Criteria Evaluations.
OEM	Original Equipment Manufacturer.
OIRA	Office of Information and Regulatory Affairs.
OMB	Office of Management and Budget.
OPA	Oil Pollution Act of 1990.
OSRO	Oil Spill Response Organization.
OSRP	Oil Spill Response Plan.
PHMSA	Pipeline and Hazardous Materials Safety Administration.
PRA	Paperwork Reduction Act.
PREP	Preparedness for Response Exercise Program.
RCPs	Regional Contingency Plans.
RFAI	Requests for Additional Information.
RIA	Regulatory Impact Analysis.
RMROL	Realistic Maximum Response Operating Limits.
RP	Recommended Practice.
RTM	Real-Time Monitoring.
SCCE	Source Control and Containment Equipment.
SCSC	Source Control Support Coordinator.
Secretary	Secretary of the Interior.
SEMS	Safety and Environmental Management Systems.
SID	Subsea Isolation Device.
SINTEF	Scientific and Industrial Research at the Norwegian Institute of Technology.
SOSC	State on Scene Coordinator.
TAP	Technical Assessment Program.
UMRA	Unfunded Mandates Reform Act of 1995.
U.S.	United States.
USCG	U.S. Coast Guard.
USFWS	U.S. Fish and Wildlife Service.
WCD	Worst Case Discharge.

I. Introduction

In May 2013, President Obama issued a document entitled, ''National Strategy for the Arctic Region'' (NSAR). The President affirmed that emerging economic opportunities exist in the region, but that ''. . . we must exercise responsible stewardship, using an integrated management approach and making decisions based on the best available information, with the aim of promoting healthy, sustainable, and resilient ecosystems over the long term.'' The NSAR is intended, among other things, to ''reduce our reliance on imported oil and strengthen our Nation's energy security'' by working with stakeholders to enable ''environmentally responsible production of oil and natural gas.'' To provide responsible stewardship of the

Arctic's environment and resources, the NSAR emphasizes the need for integrated and balanced management techniques.

Furthermore, the NSAR acknowledges the potential international implications of Arctic oil and gas activities for ''other Arctic states and the international community as a whole.'' The U.S. has committed to do its part to ''keep the Arctic region prosperous, environmentally sustainable, operationally safe, secure, and free of conflict[.]'' One primary objective outlined in the implementation plan for the NSAR is to ''reduce the risk of marine oil pollution while increasing global capabilities for preparedness and response to oil pollution incidents in the Arctic.'' (available at: *http://www.whitehouse.gov/sites/default/files/docs/implementation_plan_for_the_national_strategy_for_the_arctic_region_-_fi....pdf*). The NSAR is an example of the types of action the U.S. is taking to implement its obligations under international agreements, such as the Arctic Council's Agreement on Cooperation on Marine Oil Pollution Preparedness and Response in the Arctic (available at *http://arctic-council.org/eppr/agreement-on-cooperation-on-marine-oil-pollution-preparedness-and-response-in-the-arctic/*).

A. Resource Potential

The Arctic OCS region is estimated to contain a vast amount of undiscovered, technically recoverable oil and gas. Most of the Alaska OCS resource potential is located off the Arctic coast within the Chukchi Sea and Beaufort Sea Planning Areas. According to BOEM's 2016 Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf (mean estimates available at *http://www.boem.gov/National-Assessment-2016/,* there are approximately 23.6 billion barrels of technically recoverable oil and about 104.4 trillion cubic feet of technically recoverable natural gas in the combined Beaufort Sea and Chukchi Sea Planning Areas. This resource potential has intermittently received considerable attention from the oil and gas industry over several decades. The U.S. government has responded to this interest by holding lease sales offering millions of acres resulting in hundreds of leases, and the oil and gas industry has conducted Arctic exploration activities beginning in the 1970s.

B. Integrated Arctic Management

As ocean and seasonal conditions continue to change in the U.S. Arctic, both commercial and recreational activities will increase as more areas of water open up for longer periods of time due to the increased melting of sea ice. The decrease in summer sea ice raises legitimate concerns regarding changes to the environment and the Arctic resources that Alaska Natives depend on for survival and cultural traditions. Consistent with the Outer Continental Shelf Lands Act (OCSLA), BOEM and BSEE, the Bureaus responsible for managing oil and gas resources on the Arctic OCS, are finalizing these regulations that take into account the needs of the multiple users who have an interest in the future of the U.S. Arctic region (*see* 43 U.S.C. 1332(6)).

The U.S. has a longstanding interest in the orderly development of oil and gas resources on the Arctic OCS, while also seeking to ensure the protection of its environment and communities. The U.S. has proceeded with Arctic OCS oil and gas development to ensure that laws, regulations, and policies are created and implemented based on a thorough examination of the multiple factors at play in this unique environment. BOEM and BSEE have conducted extensive research on potential oil and gas activities on the OCS in anticipation of operations (*see, e.g., www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Categories/Arctic-Research/*), and have also evaluated the potential environmental effects of such activities (*see, e.g., http://www.boem.gov/akstudies/*). These research projects, along with other initiatives, form the basis for the most recent National policies and directives regarding Alaska OCS oil and gas development, all of which have guided this final rule.

Coordinating the future uses of the U.S. Arctic region will require integrated action between and among Federal, State, municipal and tribal governmental entities. On July 12, 2011, President Obama signed Executive Order (E.O.) 13580, establishing an Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska (E.O. 13580 Alaska Energy Permitting IWG), chaired by the Deputy Secretary of the Interior. The E.O. 13580 Alaska Energy Permitting IWG is composed of representatives from the DOI, Department of Defense, Department of Commerce, Department of Agriculture, Department of Energy, Department of Homeland Security, and the Environmental Protection Agency (EPA).[1] It is charged with facilitating ''coordinated and efficient domestic energy development and permitting in Alaska while ensuring that all applicable [health, safety, and environmental protection] standards are fully met'' (E.O. 13580, sec. 1).

The E.O. 13580 Alaska Energy Permitting IWG's report entitled, ''Managing for the Future in a Rapidly Changing Arctic, A Report to the President'' (March 2013) (*see http://www.afsc.noaa.gov/publications/misc_pdf/iamreport.pdf*), was the result of substantial collaboration and also plays a significant role in shaping U.S. Arctic policies. Further, the President signed E.O. 13689, *Enhancing Coordination of National Efforts in the Arctic* on January 21, 2015. This E.O. states the policy: ''The Arctic has critical long-term strategic, ecological, cultural, and economic value, and it is imperative that we continue to protect our national interests in the region, which include: national defense; sovereign rights and responsibilities; maritime safety; energy and economic benefits; environmental stewardship; promotion of science and research; and preservation of the rights, freedoms, and uses of the sea as reflected in international law.'' An Arctic Executive Steering Committee was established to provide guidance to Federal departments and agencies and to enhance coordination of Federal Arctic policies.

C. Overview of Regulations

Although there is currently a comprehensive OCS oil and gas regulatory program, DOI engagement with partners and stakeholders [2] and comments on the NPRM underscore the need for new and enhanced regulatory measures for Arctic OCS exploratory drilling by MODUs. For purposes of this rulemaking, exploratory drilling is defined as ''[a]ny drilling conducted for the purpose of searching for commercial quantities of oil, gas, and sulfur, including the drilling of any additional well needed to delineate any reservoir to enable the lessee to decide whether to proceed with development and production.''

This final rule defines the ''Arctic OCS'' as the Beaufort Sea and Chukchi Sea Planning Areas, as described in the

[1] The Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects was represented on the E.O. 13580 Alaska Energy Permitting IWG, but closed on March 7, 2015, due to lack of funding. Its Web site, *Arcticgas.gov*, is being maintained, but not updated, by the U.S. Arctic Research Commission, with assistance from Alaska Resources Library & Information Services (ARLIS) at the University of Alaska Anchorage. *See http://www.arcticgas.gov/.*

[2] Tribes, State and local governments, and Federal agencies are ''partners.'' ''Stakeholders'' are non-governmental organizations, industry, and other entities with an interest in this rulemaking.

Proposed Final OCS Oil and Gas Leasing Program for 2012—(June 2012) (available at: *www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf* (see pp.21–24)).[3] This definition is added to §§ 250.105, 254.6, and 550.105. As described below, BOEM and BSEE determined that these areas are both the subject of exploration and development interest and subject to conditions that present significant challenges to such operations.

This final rule applies to Arctic OCS exploratory drilling activities that use MODUs (*e.g.,* jack-ups and drillships) and related operations during the Arctic open-water drilling season (generally late June to early November). We note that, because this rulemaking is applicable only to MODUs conducting exploration drilling, the provisions finalized here do not apply to shallow water drilling from gravel islands or the use of a land rig on grounded or land-fast ice and do not prohibit these or other methods of exploratory drilling operations on the Arctic OCS.

This final rule builds on and codifies input received from partners and stakeholders, comments to the proposed rule, as well as key components of the 2012 and 2015 Arctic exploratory drilling programs. DOI released in 2013 a ''Report to the Secretary of the Interior, Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program'' (60-Day Report) (available at *http://www.doi.gov/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf*). The 60-Day Report identified a number of lessons learned and recommended practices to ensure future Arctic oil and gas exploration activities would be carried out in a safe and responsible manner.

Shell's exploratory operations proceeded in 2015 without any unexpected drilling-related problems, and it safely drilled its well to a total depth of 6800 feet. On

September 28, 2015, Shell announced that it had found indications of oil and gas in the well, but stated that the results were not sufficient to warrant further exploration of the prospect, and the well was to be plugged and abandoned in accordance with BSEE regulations. Shell subsequently announced it was ceasing further exploration activity in offshore Alaska for the foreseeable future.[4]

BOEM and BSEE have undertaken extensive environmental and safety reviews of potential oil and gas operations on the Arctic OCS. These reviews, along with concerns expressed by environmental organizations and Alaska Natives, as well as other stakeholders, highlight the need to develop additional measures specifically tailored to the operational and environmental conditions of the Arctic OCS. Arctic OCS operations can be complex, and there are challenges and operational risks throughout every phase of an exploratory drilling program.

This final rule is a combination of prescriptive and performance-based requirements that address a number of important issues and objectives, including, but not limited to, ensuring that operators:

1. Design and conduct exploration programs in a manner that accounts for Arctic OCS conditions (*e.g.,* using equipment and processes that are capable of performing effectively and safely under extreme weather and sea conditions and in remote locations with relatively limited infrastructure);

2. Develop an IOP that addresses all phases of an Arctic OCS exploration program and submit the IOP to BOEM at least 90 days in advance of filing an EP;

3. Have access to, and the ability to promptly deploy, SCCE while drilling below, or working below, the surface casing;

4. Have access to a separate relief rig located in a geographic position to be able to timely drill a relief well under the conditions expected at the site;

5. Have the capability to predict, track, report, and respond to ice conditions and adverse weather events;

6. Effectively manage and oversee contractors; and

7. Develop and implement OSRPs that are designed in a manner that accounts for the unique Arctic OCS operating environment and that describe the availability of the necessary equipment, training, and personnel for oil spill response on the Arctic OCS.

D. Costs and Benefits of Final Rule

The Final Regulatory Impact Analysis (RIA) for this final rule estimates that the new requirements could result in compliance costs for the industry of $2.05 billion under 3-percent discounting and $1.74 billion under 7-percent discounting over 10 years. The provisions of the rule subsumed within the regulatory baseline are estimated to cost $1.83 billion under 3-percent discounting and $1.51 billion under 7-percent discounting over the 10-year analysis period. As discussed in Section V.B of the preamble, the baseline includes the estimated costs associated with current regulatory requirements and industry standards. While the economic and other benefits of the final rule—based primarily on preventing or reducing the severity or duration of catastrophic oil spills—are difficult to quantify, BOEM and BSEE have determined that it is appropriate to proceed with this final rule. Although the probability of a catastrophic oil spill is low, the *Deepwater Horizon* oil spill demonstrated that even such low probability events can have devastating human, economic and environmental results if they occur.

Reducing the risks of Arctic OCS operations is particularly important because of the unique significance to Alaska Natives of the marine mammals, fish, and migratory birds, in the lands and waters around the Arctic OCS. Ensuring a continuing opportunity to harvest these subsistence resources is critical for protecting Alaska Natives' health, livelihood, and culture. Additionally, adequately protecting the health of the Arctic ecosystem, including the sensitive environment and wildlife, is particularly important and highly valued. Thus, the impact of a catastrophic oil spill, while a remote possibility, would have extremely high cultural and societal costs, and prevention of such a catastrophe would have correspondingly high cultural and societal benefits.

The requirements of the rule—specifically tailored to the Arctic OCS—provide additional specificity regarding BOEM's and BSEE's expectations for safe and responsible development of U.S. Arctic resources and outline the particular actions that lessees, owners, and operators must take to meet those expectations. BOEM and BSEE do not anticipate that these requirements, or their associated costs, will prevent lessees and operators from conducting exploratory drilling on their leases. In pursuing such operations, Arctic OCS lessees and operators are well aware of the significant challenges presented by Arctic OCS conditions, and the final rule largely reflects clarification and codification of the Bureaus' expectations under existing regulations and industry standards for the relevant operations. In fact, the additional clarity and specificity provided by the final

[3] This final rule uses and defines terms that may be similar to terms used in other programs by other Federal agencies; however, the terms and definitions used in this final rule are intended to apply only to the BSEE and BOEM regulatory programs covered by this final rule, unless otherwise noted.

[4] Shell update of Alaska exploration, Press release (September 28, 2015) (available at *http://www.shell.com/global/aboutshell/media/news-and-media-releases/2015/shell-updates-on-alaska-exploration.html*).

rule should assist the oil and gas industry to plan better and to more effectively conduct exploratory drilling on the Arctic OCS with lower risk. As discussed later in this final rule, the positive impact of such production on U.S. energy independence and energy security could be substantial if hydrocarbon resources can be extracted and marketed economically. Thus, this final rule would help achieve the NSAR goals of protecting the unique and sensitive Arctic ecosystems, as well as the subsistence-based health and culture of nearby Alaska Native communities, while reducing reliance on imported oil and strengthening National energy security.

E. Availability of Incorporated Documents for Public Viewing

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

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

BSEE incorporates by reference in its regulations many oil and gas industry standards in order to require compliance with those standards in offshore operations. When a copyrighted publication is incorporated by reference into BSEE regulations, BSEE is obligated to observe and protect that copyright. BSEE provides members of the public with 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. These standards represent almost one-third of all API standards and include all that are safety-related or are incorporated into Federal regulations. One of those standards is incorporated by reference in this final rule. In addition to the free online availability of the standard 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.*[5]

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; phone: 703–787–1665.

F. Summary of Documents Incorporated by Reference

This rulemaking is substantive in terms of the content that is explicitly stated in the rule text itself, and it also incorporates by reference a technical standard concerning structures and pipelines for offshore Arctic conditions. A brief summary of the standard follows.

ANSI/API Recommended Practice 2N, Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions

This standard was developed in response to the offshore industry's demand for a coherent and consistent definition of methodologies to design, analyze, and assess arctic and cold region offshore structures. This standard also addresses issues such as topsides, winterization, and escape, evacuation, and rescue that go beyond what is strictly necessary for the design, construction, transportation, installation, and decommissioning of the structure. These issues are essential for offshore operations in arctic and cold region conditions and they are not covered in other standards. When future editions of this and other standards are prepared, effort will be made to avoid duplication of scope.

[5] 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.

II. Background

A. Statutory and Regulatory Overview

1. Procedural History

On February 24, 2015, BOEM and BSEE published an NPRM in the **Federal Register** entitled, ''Oil and Gas Operations in the Outer Continental Shelf—Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf'' (80 FR 9916). In response to several commenters' requests, we published a 30-day extension of the comment period for the NPRM on April 20, 2015 (80 FR 21670). We received 1,311 letters to the docket for the rulemaking, from over 100,000 individual commenters on the NPRM. We summarize these comments in the preamble of this final rule in Section IV.B *Discussion of and Responses to Comments.* Between June 6, 2013 and July 15, 2016, BOEM and BSEE held several meetings as part of tribal consultations on this rulemaking in the following Alaskan locations: Kotzebue, Point Hope, Point Lay, Barrow, Wainwright, and via teleconference with Nuiqsut. Comments received from Alaska Native Tribes and ANCSA Corporations, both written and oral, are summarized in Section IV.B. Discussion of these consultations with Alaska Native Tribes and Corporations appears in the preamble at Section V.I *Consultation with Indian Tribes (E.O 13175).*

2. OCSLA

The 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's 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] . . .'' which ''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 the OCSLA to BOEM and BSEE, both of which are charged with administering and regulating aspects of the Nation's OCS oil and gas program (see § 250.101 and § 550.101). BOEM and BSEE work to promote safety, protect the environment, and conserve offshore resources through vigorous regulatory oversight.

BOEM manages the development of the Nation's offshore energy resources in an environmentally and economically responsible way. BOEM's functions include leasing; exploration, development and production plan administration and review; environmental analyses to ensure compliance with the National Environmental Policy Act of 1969 (NEPA); environmental studies; resource evaluation; economic analysis; complying with other Federal laws (*e.g.,* the Endangered Species Act (ESA)); and management of the OCS renewable energy program.

BSEE performs offshore regulatory oversight and enforcement to ensure safety and environmentally sound performance during operations, and the conservation of OCS resources, by, among other things, evaluating drilling permits, and conducting inspections to ensure compliance with laws, regulations, lease terms, and approved plans and permits.

Prior to commencing exploration for oil and gas on the OCS, OCSLA and its implementing regulations (43 U.S.C. 1340(c)(1); § 550.201(a)) require lessees to submit an EP to BOEM for approval. An EP must include information such as a schedule of anticipated exploration activities, equipment to be used, the general location of each well to be drilled, and any other information deemed pertinent by BOEM (§§ 550.211 through 550.228).

However, approval of an EP does not by itself permit the lessee to proceed with exploratory drilling. After the EP is approved, the lessee must submit to BSEE an Application for Permit to Drill (APD), which BSEE must approve before a lessee may drill a well (43 U.S.C. 1340(d); § 250.410)). The APD must be consistent with the approved EP and include information on the well location, the drilling design and procedures, casing and cementing programs, the diverter and Blowout Preventer (BOP) systems, MODU (if one is used), and additional information requested by the District Manager.

BOEM evaluates EPs, and BSEE evaluates APDs, to determine whether the operator's proposed activities meet the OCSLA's standards and each Bureau's regulations governing OCS exploration. The regulatory requirements include, but are not limited to, ensuring that the proposed drilling operation:

i. Conforms to OCSLA, as amended, its applicable implementing regulations, lease provisions and stipulations, and other applicable laws;

ii. Is conducted in a safe manner;

iii. Conforms to sound conservation practices and protects the rights of the U.S. in the mineral resources of the OCS;

iv. Does not unreasonably interfere with other uses of the OCS; and

v. Does not cause undue or serious harm or damage to the human, marine, or coastal environments (§§ 250.101 and 250.106; 550.101 and 550.202).

Based on these evaluations, BOEM and BSEE will approve the lessee's (or operator's) EP and APD, require the lessee (or operator) to modify its submissions, or disapprove the EP or APD (§§ 250.410; 550.233).

3. The Oil Pollution Act of 1990 (OPA) and Clean Water Act (CWA)

Congress passed the OPA, 33 U.S.C. 2701 *et seq.,* following the *Exxon Valdez* oil spill. The OPA amended the CWA, 33 U.S.C. 1251 *et seq.,* by, among other things, adding OSRP requirements for offshore facilities. The OPA provides for prompt federally coordinated responses to offshore oil spills and for compensation of spill victims. It also calls for the issuance of regulations prohibiting owners and operators of offshore facilities from operating or handling, storing, or transporting oil until:

i. They have prepared and submitted ''a plan for responding, to the maximum extent practicable, to a worst case discharge (WCD), and to a substantial threat of such a discharge, of oil . . .;''

ii. The plan ''has been approved by the President;'' and

iii. The ''facility is operating in compliance with the plan'' (OPA section 4202(a), codified at 33 U.S.C. 1321(j)(5)(A)(i) and (F)(i)–(ii)).

E.O. 12777 (October 18, 1991) delegated to the Secretary the functions of 33 U.S.C. 1321(j)(5) and (j)(6)(A) related to offshore facilities (other than deep water ports). This includes the promulgation of regulations governing the obligation to prepare and submit OSRPs, the review and approval of OSRPs, and the periodic verification of spill response capabilities related to these plans. Those applicable regulations are administered by BSEE and are at parts 250 and 254. E.O. 12777 also delegated to the Secretary the authority to implement, for offshore facilities, 33 U.S.C. 1321(j)(1)(C), which provides for the issuance of regulations ''establishing procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances from . . . offshore facilities, and to contain such discharges.''

B. Factual Overview of the Arctic OCS Region

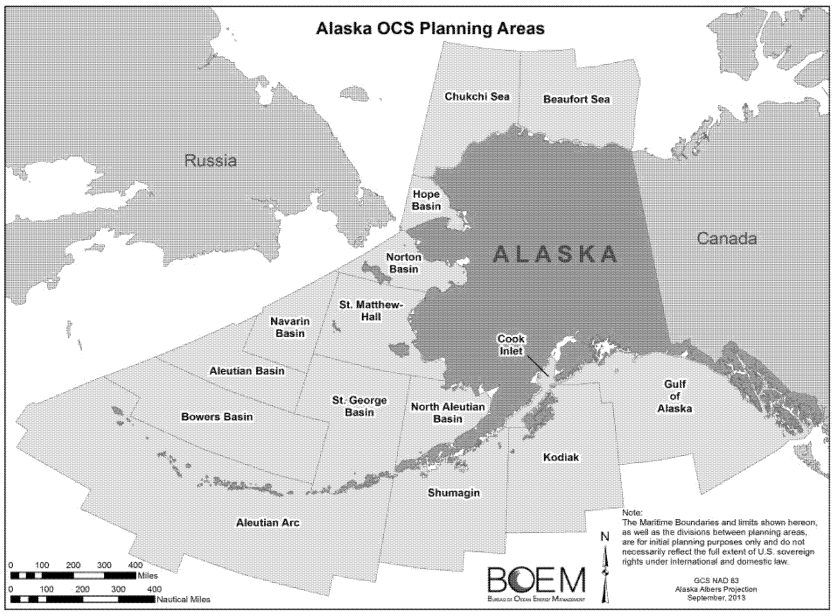
1. Arctic OCS Oil and Gas Activity

There has been a renewed interest in the oil and gas potential of the Alaska OCS since the first exploratory wells were drilled in the late 1970s. The majority of exploratory drilling north of the Arctic Circle has occurred where the greatest oil and gas resource potential exists, namely the Beaufort Sea and Chukchi Sea Planning Areas (*see* Figure 1). A total of 30 exploratory wells have been drilled on the Beaufort OCS since the first Federal OCS leases were offered, and more wells have been drilled beneath the near-shore Beaufort Sea under the jurisdiction of the State of Alaska. The Chukchi Sea Planning Area has a more limited history of leasing and exploration. Before 2012, only a total of five exploratory wells had been drilled there (between 1989 and 1991[6]), and no explored prospect was considered economically viable for development.

Until Shell's 2012 and 2015 exploratory operations, there had been only one exploratory well drilled on the Arctic OCS since 1994—the 2003

[6] *See* BOEM Alaska Region Web site available at *www.boem.gov/About-BOEM/BOEM-Regions/Alaska-Region/Historical-Data/Index.aspx.*

exploratory well near Prudhoe Bay in the Beaufort Sea (*see* BOEM Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf (2016). In 2012, Shell drilled two ''top hole'' wells (*i.e.,* a partial well not intended to enter hydrocarbon zones), one in the Chukchi Sea (Burger Prospect) and the other in the Beaufort Sea (Sivulliq). In 2015, Shell completed an exploratory well in the Burger prospect of the Chukchi Sea; however, according to Shell, indications of oil and gas were ''not sufficient to warrant further exploration in the Burger prospect.'' [7]



[Figure 1]

With the exception of three OCS leases making up a portion of the Northstar oil field, currently operated by Hilcorp Alaska, LLC, from State submerged lands in the Beaufort Sea, no production has yet resulted from Alaska OCS leases.

2. Challenges to U.S. Arctic Oil and Gas Operations

The challenges to conducting operations and responding to emergencies in the extreme and variable environmental and weather conditions in the Arctic are demanding. Both the Beaufort Sea and Chukchi Sea Planning Areas experience sub-freezing temperatures during most of the year, extended periods of low-light visibility, significant fog cover in the summer, strong winds and currents, storms that produce freezing spray and dangerous sea states, snow, and significant ice cover. During the fall (September–November), conditions become increasingly inhospitable as air temperatures decrease, wind speeds increase, storms become more frequent, and sea ice begins to form, all of which make Arctic OCS exploratory drilling operations more challenging.[8] Other challenges to conducting operations and responding to emergencies on the Arctic OCS include the geographical remoteness and relative lack of established infrastructure to support oil and gas operations, as well as the presence of protected marine mammals and Alaska Native subsistence activities.

III. Regulations for Arctic OCS Exploratory Drilling

The existing OCS oil and gas regulatory regime is extensive and covers all offshore facilities or operations in any OCS region, as appropriate and applicable, including the Arctic OCS. BOEM and BSEE apply these regulations while overseeing OCS leasing, exploration, development, production, and decommissioning. Operators are subject to the same regulatory requirements, such as: Application procedures and information requirements for exploration, development, and production activities; pollution prevention and control; safety requirements for casing and cementing and the use of a BOP and diverter systems; design, installation, use and maintenance of OCS platforms to ensure structural integrity and safe and environmentally protective operations; decommissioning; development and implementation of Safety and Environmental Management Systems (SEMS); and preparation and submission of OSRPs (*see generally* 30 CFR parts 250, 254, and 550).

The existing regulations also contain provisions that apply to specific regions or atypical activities or operating conditions, especially, for example, where drilling occurs in deep water or in a ''frontier'' area (typically characterized by its remote location and limited infrastructure and operational history, such as the Arctic OCS region).

[7] *http://www.shell.com/global/aboutshell/media/news-and-media-releases/2015/shell-updates-on-alaska-exploration.html.*

[8] *See* Environmental Assessments for Shell Offshore, Inc.'s Revised Outer Continental Shelf Lease Exploration Plan, Camden Bay, Beaufort Sea, Alaska (2011), Revised Outer Continental Shelf Lease Exploration Plan, Chukchi Sea, Alaska, Burger Prospect (2015), and Shell Gulf of Mexico, Inc.'s Revised Chukchi Sea Exploration Plan Burger Prospect (2011); BOEM Alaska Region Web site available at *http://www.boem.gov/About-BOEM/BOEM-Regions/Alaska-Region/Environment/Environmental-Analysis/Environmental-Impact-Statements-and-Major-Environmental-Assessments.aspx.*

In these situations, BOEM and BSEE have special requirements, such as information and design requirements for deep-water development projects (§§ 250.286 through 250.295); use of appropriate equipment, third-party audits, and contingency plans in frontier areas or other areas subject to subfreezing conditions (§§ 250.713(c) and 250.418(f)); the placement of subsea BOP systems in mudline cellars when drilling occurs in areas subject to ice-scouring (§ 250.738); and emergency plans and critical operations and curtailment procedures information in the Arctic OCS Region (§§ 550.220 and 550.251).

Though there is currently a generally applicable OCS oil and gas regulatory program, there is a need for new and amended regulatory measures specifically for Arctic OCS exploratory drilling by MODUs. This final rule, in combination with the existing regulations (which continue to apply to Arctic OCS operations unless otherwise expressly stated) will ensure that exploratory drilling operations are well planned from the outset and conducted safely and responsibly in relation to the unique Arctic environment and the local communities that are closely connected to the region and its resources. The key elements of the final rule are as follows:

A. Measures That Address Recommendations

The final rule addresses recommendations contained in several recent reports on OCS oil and gas activities, including the Arctic Council, Arctic Offshore Oil and Gas Guidelines (2009); the National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling (2011); Ocean Energy Safety Advisory Committee Recommendations (2013); DOI's 60-Day Report (2013); the E.O. 13580 Alaska Energy Permitting IWG's report entitled, ''Managing for the Future in a Rapidly Changing Arctic, A Report to the President'' (March 2013); the NSAR (May 2013); the Arctic Council, Arctic Offshore Oil and Gas Guidelines: Systems Safety Management and Safety Culture (March 2014); and the National Petroleum Council (NPC), Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources (2015).

B. Approval of Alternate Procedures or Equipment

Numerous comments were submitted on the NPRM requesting a more performance-based approach to regulating exploratory drilling operations on the Arctic OCS. As discussed in depth in Section IV. B, *Discussion of and Responses to Comments,* we are aware that methods for source control and containment, securing a well, or killing and permanently plugging an out-of-control well on the Arctic OCS may include available technology for which there are no recognized industry standards or best practices. Accordingly, several of the final regulations are intended to convey an overarching performance requirement. For example, the operator must have the means available to secure any uncontrolled flow of hydrocarbons and kill the out-of-control well prior to seasonal ice encroachment. The regulations also provide prescriptive elements establishing means to comply with that requirement using existing, proven technology. And finally, the regulations provide a clear pathway towards alternative compliance measures to account for future technological advances. To further clarify our intent, we are revising the proposed language of both § 250.471, *What are the requirements for Arctic OCS source control and containment?,* and § 250.472, *What are the relief rig requirements for the Arctic OCS?* Paragraph (a) of § 250.471 is revised and a new paragraph (i) in § 250.471 is added to clearly convey the performance standard an operator must be able to demonstrate when requesting approval for alternative procedures or equipment to the SCCE—*i.e.,* response capabilities able to stop or capture the flow of an out-of-control well. Similarly, we are also revising the provisions at paragraphs (a) and (c) of § 250.472 to clarify that alternative procedures or equipment to the relief rig requirements must be capable of killing and permanently plugging an out-of-control well in less than 45 days.

Furthermore, existing regulations will continue to allow operators to use new and emergent technology on the OCS in certain circumstances and upon demonstrating adequate safety and environmental protection. Under § 250.141, *May I ever use alternate procedures or equipment?,* the District Manager or Regional Supervisor may approve the use of alternate procedures or equipment provided the operator can show the technology will meet or exceed the level of safety and environmental protection required by the current regulations. This provision enables operators to request approval for innovative technological advancements that may provide additional flexibility, provided the operator clearly establishes that such technology will meet or exceed the level of protection provided by the regulatory requirements. The operator is responsible for providing sufficient data to BSEE to adequately demonstrate the safety of the technology or operations. To obtain approval under § 250.141, an operator should submit information regarding its proposed alternate technology, which could include:

1. Laboratory tests results, test protocols, test procedures, testing methodologies, Quality Assurance/Quality Control provisions, manufacturer testing, and/or qualification or accreditation procedures implemented by an independent third party relevant to the performance characteristics of such equipment when used in a real world environment;

2. Actual operational performance of such equipment if previously used or currently being used in other areas under similar conditions; and

3. Additional studies, evaluations, or risk and/or hazards analyses relevant to the equipment or procedures under consideration.

C. IOP Requirement

During exploratory drilling operations on the Arctic OCS, operators may face substantial environmental challenges and operational risks throughout every phase of the endeavor, including preparations, mobilization, in-theater drilling operations, emergency response and preparedness, and demobilization. Thorough advanced planning is critical to mitigating these challenges and risks. One of the key components of this final rule is a requirement that operators explain how their proposed Arctic OCS exploratory drilling operations are fully integrated from start to finish in a manner that accounts for Arctic OCS conditions and that they provide this information to DOI at an early stage of the planning process.

This final rule requires that operators develop and submit IOPs to BOEM at least 90 days in advance of filing their EPs. The purpose of the IOP is to describe, at a strategic or conceptual level, how exploratory drilling operations will be designed, executed, and managed as an integrated endeavor from start to finish. The IOP is intended to be a concept of operations that includes a description of pertinent aspects of an operator's proposed exploratory drilling activities and supporting operations and how the operator will design and conduct its program in a manner that accounts for the challenges presented by Arctic OCS conditions. The primary issues that operators must address in their IOPs include:

1. Vessel and equipment designs and configurations;
2. The overall schedule of operations, including contractor work on critical components;
3. Mobilization and demobilization operations and maintenance schedule(s);
4. In-theater drilling program objectives and timelines for each objective;
5. Weather and ice forecasting and management capabilities;
6. Contractor management and oversight;
7. Operational safety principles;
8. Preparation and staging of spill response assets;
9. Impact on local community infrastructure, including but not limited to housing, energy supplies and services; and
10. Extent the project will rely on local community workforce and spill clean-up response capacity.

DOI recognizes that other Federal agencies have primary oversight responsibility for some of the previously listed activities. Upon receipt of the IOP, DOI would engage with members of the E.O. 13580 Alaska Energy Permitting IWG and promptly distribute the IOP to the State of Alaska and Federal government agencies making up the Alaska Energy Permitting IWG and others that are involved in the review, approval, or oversight of various aspects of OCS operations.

However, the IOP process does not entail any mechanism through which agencies can or must approve the operator's proposed activities described in the IOP. The IOP is intended to be a conceptual, informational document designed to ensure that an operator has planned to address risks associated with the full suite of regulated activities, and to provide the relevant regulatory agencies a preview of an operator's approach to regulatory compliance and integrated planning. It is also anticipated that an operator would already develop much of this requested information as a part of its internal planning for potential activity. Thus, the IOP enables relevant agencies to familiarize themselves, early in the planning process, with the operator's overall proposed program from start to finish. This, in turn, allows DOI and those agencies to coordinate and provide early input to the operator regarding potential issues presented by the proposed activities with respect to any future EP reviews and permitting requirements, including aspects of the program that might require additional details or refinement. The IOP requirement—and the final rule in general—will not, however, interfere with or supplant operators' obligations to comply with all other applicable Federal agency requirements. Each agency that receives an IOP would continue to review the relevant details of an operator's planned activities for compliance with that agency's regulatory requirements in the appropriate manner and at the appropriate time under its own regulatory program.

D. SCCE and Relief Rig Capabilities

In Arctic OCS exploratory drilling, there is a need for operators to demonstrate that they have access to, and could promptly deploy, well control and containment resources that would be adequate to respond to a loss of well control. This equipment is readily available and accessible in the Gulf of Mexico due to the level of activity in that area, but is not similarly available in the Arctic as a matter of normal course. Ensuring that operators have redundant protective measures in place is critical, as there is no guarantee that a single measure could control or contain a WCD. Therefore, BSEE is requiring that operators who use a MODU for Arctic OCS exploratory drilling must be able to stop or capture the flow of an out-of-control well by having access to, and the ability to deploy, SCCE (*e.g.,* a capping stack, cap and flow system, and containment dome) within the timeframes discussed in this final rule and that the SCCE be capable of functioning in Arctic OCS conditions.

BSEE is also requiring operators to have access to a separate relief rig, staged at a location such that it could arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site and in no event later than 45 days after the loss of well control. This equipment is fundamental to safe and responsible operations on the Arctic OCS, where existing infrastructure is sparse, the geography and logistics make bringing equipment and resources into the region challenging, and the time available to mount response operations is limited by changing weather and ice conditions, particularly at the end of the drilling season.

The 45-day period is the maximum time allowed for conducting relief rig operations. However, it is a performance-based requirement and leaves the means of compliance up to the operator. The operator may seek to demonstrate its ability to complete relief well operations in less than 45 days, subject to review by BOEM in the EP process under § 550.22(c)(4) and BSEE's review during the APD process under § 250.470(c). The length of the ''shoulder season'', or the period of time operators may not drill or work below the surface casing, depends upon how long operations related to the use of a relief rig can be expected to take. An operator must demonstrate how long it will take for a relief rig to arrive on site, drill a relief well, kill and abandon the original well and abandon the relief well prior to expected seasonal ice encroachment at the drill site (or trigger date). In evaluating this demonstration, consideration may be given to a number of factors, including but not limited to: The distance of drilling operations to the shore; available infrastructure; and the capacity and location of oil spill response equipment. The trigger date, established by BOEM (in consultation with the National Weather Service (NWS) and the operator)), restricts when the operator can drill or work below the surface casing in order to address risks associated with late season drilling and ensure an opportunity for spill response and cleanup in favorable conditions. BSEE notes the operator's actual timeframe to drill a relief well would be based on consideration of the distance between anticipated exploratory drilling sites, the availability of adequate staging locations for relief rigs, the length and complexity of rig transit, and the time necessary to complete the requisite operations once on-site. The 45-day maximum timeframe is intended to ensure a timely response and prevent an extended uncontrolled flow of hydrocarbons in the event of a loss of well control early in the open water season.

As discussed previously in Section III.B, we have revised the proposed language for the SCCE provisions at paragraph (a) of § 250.471 and added a new paragraph (i) in § 250.471, and revised the relief rig provisions at paragraphs (a) and (c) of § 250.472, to clearly state the standards operators must meet to satisfy the requirements, while also alternatively providing that operators may request approval of an alternate technology under existing § 250.141, if the operator can show the alternate technology will meet or exceed the level of safety and environmental protection provided by the SCCE and relief rigs requirements. This provision enables operators to request approval for innovative technological advancements that may provide additional flexibility.

E. Planning for the Variability and Challenges of the Arctic OCS Conditions

Reliable weather and ice forecasting play a significant role in ensuring safe

operations on the Arctic OCS. Advanced forecasting and tracking technology, information sharing among industry and government, and local knowledge of the operating environment are essential to managing the substantial challenges and risks that Arctic OCS conditions pose for all OCS operations. In light of the threats posed by ice and extreme weather events, BOEM and BSEE require that operators include in their IOPs, EPs, and APDs, at appropriate levels of specificity for each document, a description of their weather and ice monitoring and forecasting capabilities for all phases of their exploration program, as well as their alert procedures and thresholds for activating ice and weather management systems. Once operations commence, this rule requires operators to:

1. Notify BOEM and BSEE immediately of any sea ice movement or condition that has the potential to affect operations or trigger ice management activities; and

2. Notify BSEE of the start and termination of ice management activities and submit written reports after completing such activities.

F. Arctic OCS Oil Spill Response Preparedness

Operators need to be prepared for a quick and effective response in the event of an oil spill on the Arctic OCS and be ready to coordinate activities with the Federal government and other stakeholders. The OSRPs and related activities should be tailored to the unique Arctic OCS operating environment to ensure that operators have the necessary equipment, training, and personnel. Among other things, this final rule establishes specific planning requirements to maximize the application of oil spill response technology and ensure a coordinated response system designed to address the challenges inherent to the U.S. Arctic region.

G. Reducing Pollution From Arctic OCS Exploratory Drilling Operations

Partners, primarily Alaska Native Tribes, as well as other stakeholders expressed concern that mud and cuttings from exploratory drilling could adversely affect marine species (*e.g.,* whales and fish) and their habitat and compromise the effectiveness of subsistence hunting activities. Existing environmental analyses support these concerns regarding petroleum based mud and cuttings and also demonstrate that such discharges could affect water quality, benthic habitat, and marine organisms within the localized area (*see, e.g.,* Shell Revised Outer Continental Shelf Lease Exploration Plan, Chukchi Sea, Alaska, Burger Prospect (2015)).

BSEE is requiring the capture of all petroleum-based mud and associated cuttings from Arctic OCS exploratory drilling operations to prevent the discharge of such pollutants into the marine environment. The new provision also clarifies the Regional Supervisor's discretionary authority to require that operators capture all water-based mud and associated cuttings from Arctic OCS exploratory drilling operations (after completion of the hole for the conductor casing) to prevent their discharge into the marine environment. The Regional Supervisor would exercise this discretion based on various factors, such as the proximity of exploratory drilling operations to subsistence hunting and fishing locations or the extent to which such discharges might cause marine mammals and birds to alter their migratory patterns in a manner that interferes with subsistence activities or might adversely affect marine mammals, fish, birds, or their habitat(s).

H. Oversight, Management, and Accountability of Operations and Contractor Support

An effective risk management framework at the beginning of a project incorporates many components, including planning, vessel design, contractor selection, and an assessment of regulatory requirements for all facets of the project. DOI is requiring that operators provide an explanation, starting in the IOP, at a conceptual level, of how they would apply their oversight and risk management protocols to both their personnel and their contractors to support safe and responsible exploratory drilling. These new regulations, in conjunction with DOI's existing regulations, require varying levels of information about operator safety and oversight management at progressive stages of the planning and approval process. This would start with the most general information and increase the level of detail with successive regulatory submittals, as the project proceeds from planning to implementation (*e.g.,* IOP to EP to APD).

In addition, the final rule requires Arctic OCS operators to:

1. Report threatening sea ice conditions and ice management activities, and unexpected operational issues that could result in a loss of well control;

2. Conduct real-time monitoring of various aspects of well operations,

3. Increase their SEMS auditing frequency; and,

4. Enhance their oil spill preparedness and response capabilities for Arctic OCS operations.

A summary of the changes that this final rule makes to the provisions proposed by the NPRM follows:

IV. Section-By-Section Discussion of Changes and Comments

This section summarizes the requirements proposed in the NPRM and how they are addressed in this final rule. Some of these provisions received no comments during the public comment period, while other provisions were supported or criticized by certain commenters. Section IV.A discusses the changes from the proposed to the final rule. Section IV.B discusses the public comments received and our responses to the comments. Many of these provisions and concepts are described in more detail above in Section III.

A. Summary of Key Changes From the NPRM

This section includes a description of how the final rule differs from the provisions proposed by the NPRM (80 FR 9916 (February 24, 2015)) along with an explanation of why the changes in the final rule are necessary. For a full discussion of comments and BOEM and BSEE responses, see section IV.B *Discussion of and Responses to Comments.*

Definitions. (§ 250.105)

BSEE is revising the proposed definition of ''capping stack'' to clarify that the required capping stack may be pre-positioned. Although the proposed definition did not preclude the use of a pre-positioned capping stack, in response to comments we determined a clarification to the definition of capping stack is appropriate. Accordingly, the addition of the clarification that the capping stack may be pre-positioned to the definition does not create a new category of capping stack, but instead clarifies that the use of a capping stack is not limited to subsea wellheads when surface BOPs are used. The revised definition makes clear that pre-positioned capping stacks may be used below subsea BOPs. BSEE will evaluate the use of a pre-positioned capping stack as a part of an operator's proposal on a case-by-case basis and approve their use when deemed technically and operationally appropriate, such as when the operator proposes to use a jack-up rig with surface trees.

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

BSEE is revising the language of proposed § 250.402(c)(2) to clarify the

circumstances under which BSEE may approve an equivalent means to satisfy the requirement that, in areas of ice scour, an operator must use a mudline cellar. We note the former § 250.402 was removed and reserved and the contents were moved to § 250.720 in the Blowout Preventer Systems and Well Control Final Rule (Well Control Rule) (80 FR 25888) published April 29, 2016. Therefore, the revisions to proposed § 250.402(c)(2) discussed here have been finalized as § 250.720(c)(2) in this rulemaking. The proposed rule provided that the operator may use an equivalent means to minimize the risk of damage to the well head. In response to comments expressing concern for the operational risks presented by the mudline cellar when using a jack-up rig, BSEE has clarified what an operator should show when requesting to utilize an equivalent alternative that minimizes risk to both the well head and the wellbore. Having a mudline cellar in place to protect the well head and wellbore provides an additional protection against a loss of well control and possible release of hydrocarbons to the environment. Accordingly, we have revised the language to clarify that an operator seeking approval of an equivalent means must show that a mudline cellar would create operational risks, as finalized at § 250.720(c) as set out in the regulatory text at the end of this document.

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

The proposed amendments to § 250.447(b) are not being included in the final rule. BSEE has decided to maintain the same 14-day BOP pressure test cycle on the Arctic OCS as is required elsewhere on the OCS. The existing regulation in paragraph (a)(4) of § 250.737 provides that the District Manager or Regional Supervisor may require more frequent testing if conditions or BOP performance warrant.

As discussed in Section IV.B, *Discussion of and Response to Comments,* many commenters to the proposed 7-day BOP testing requirement were concerned that increasing the number of pressure tests may reduce the reliability of the equipment by degrading the sealing capability of the elements within the BOP stack and would not necessarily demonstrate the future performance of the equipment. Commenters also asserted that the requirement for operators to stop drilling operations to perform a pressure test could ultimately increase the likelihood of an incident occurring. The BOP is a critical line of defense against loss of well control. Ensuring the proper functioning of the BOP is essential to all OCS drilling operations BSEE considered whether the integrity of BOPs could be compromised by Arctic OCS conditions; in particular, BSEE considered the possible effects of extreme weather conditions on BOPs maintained on surface vessels or facilities (such as jack-up rigs). At this time, pressure tests and functional tests are the primary methods for ensuring the performance of BOPs. BSEE considered these and other issues raised via public comments and has determined not to require increased testing frequency on the Arctic OCS.

BSEE recognizes the importance of ensuring the proper functioning of the BOP. Shell proposed a 7-day BOP testing cycle in 2012, and BSEE ultimately approved that approach for Shell. We proposed in the NPRM to require a similar testing frequency for all Arctic OCS exploratory drilling operations, due to the possibility that the integrity of BOPs could be compromised by Arctic conditions. BSEE specifically requested comments on the appropriateness of the proposed 7-day testing frequency to demonstrate the reliability of the equipment under Arctic conditions; any additional safety issues that might arise from this increased testing or that would be unique to Arctic operations; and all potential drilling impacts related to the proposed 7-day testing frequency.

Comments on BOP testing frequency fell largely into two groups: Supporters of the 14-day (or longer) test cycle and supporters of the 7-day test cycle. BSEE considered all of the comments, the information and justifications provided by the commenters, and various studies in deciding the appropriate test frequency. After careful consideration, BSEE determined that increasing the testing frequency to 7-days could cause increased wear-and-tear and fatigue on the equipment, without measurably increasing the reliability of the BOPs. No significant evidence was presented by supporters of a 7-day test cycle that demonstrated that more frequent testing in all situations would increase safety, and no evidence was presented for why BSEE should have a different requirement for BOP pressure tests in the Arctic than elsewhere on the OCS.

Therefore, in the final rule BSEE removed the proposed amendments that would have required operators to test their BOP systems every 7 days during Arctic OCS exploratory drilling operations. Existing regulatory provisions address similar protection concerns. Paragraph (a)(4) of § 250.737 allows for the District Manager, to require more frequent testing if conditions (Arctic or otherwise) or the BOP performance warrant. Additionally, § 250.737(d)(9) requires a function test of the annular and ram BOPs every 7 days, between pressure tests, ensuring the BOP rams will function in all operating conditions.[9]

What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations? (§ 250.452)

BSEE is revising the proposed § 250.452 to clarify the operator's responsibilities for complying with the real-time monitoring (RTM) requirements.

Paragraph (a) of § 250.452 is revised by deleting the phrase ''all aspects of'' from the provision identifying what functions must be monitored. This revision allows the operator flexibility in determining which elements of the identified functions will be monitored. The operator is responsible for recording, storing, and transmitting data regarding the BOP system; the well fluid's handling systems on the rig; and the well's downhole conditions as monitored by a downhole sensing system, when such a system is installed. The operator will determine what functional aspects of these systems should be monitored to meet the performance requirements of this provision.

BSEE has revised paragraphs (a) and (b) of § 250.452 to make clear that it is not necessary to cease operations because of a temporary loss of the RTM data feed due to a failure or interruption in the RTM data feed to shore. In this type of situation, the operator should have the ability to gather and record the data in the control room of the offshore unit and transmit the data to shore once the data feed is restored. To clarify this, we deleted the word ''immediately'' from paragraph (b) of § 250.452 and added the phrase ''as they are gathered, barring unforeseeable or unpreventable interruptions in transmissions,'' to describe the proper timing of the data transmission. Additionally, to clarify that in the event of a failure or interruption of the datalink the operator should continue collecting RTM data, we added qualifying language to paragraph (a) in § 250.452, providing that the monitoring system must be ''independent, automatic, and

[9] Throughout this preamble, the Bureaus refer to regulatory provisions promulgated through the recently-finalized Blowout Preventer Systems and Well Control Rule (81 FR 25888 (April 29, 2016)) (WCR). To accommodate the respective timing of these rules, those references and the related discussions of the relevant WCR provisions are based upon the working assumption that those elements of the WCR go into effect as promulgated.

continuous'' to ensure the operator is able to transmit data, even if not immediately, in a timely and appropriate manner.

We have also revised paragraph (b) in § 250.452 by deleting the proposed text: ''and who have the authority, in consultation with rig personnel, to initiate any necessary action in response to abnormal data or events.'' BSEE recognizes that operators typically seek to ensure that command and control decision making is primarily the responsibility of the onboard rig personnel, and that the RTM support personnel typically function in an advisory capacity. The RTM monitoring requirements seek to help improve, not disrupt, the ability of onboard rig personnel to monitor operations and assess and mitigate risks.

The final clarifying revision to paragraph (a) in § 250.452 tightens the language, changing from the proposed ''you must have real-time data gathering and monitoring, capability to record, store, and transmit data'' to now read: ''you must gather and monitor real-time data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data.'' Other than as discussed above, these revisions are designed to make the regulatory language clearer and easier to understand and apply.

What are the requirements for Arctic OCS source control and containment? (§ 250.471)

As discussed in Sections III.B *Approval of Alternate Procedures or Equipment* and III.D *SCCE and Relief Rig Capabilities,* BSEE is revising the language proposed in § 250.471 to clarify that operators using a MODU when drilling below or working below the surface casing must have access to SCCE that is capable of stopping or capturing the flow of an out-of-control well. Accordingly, we are revising § 250.471(a) to clearly state that the operator must have access to SCCE equipment capable of ''stopping or capturing the flow of an out-of-control well''. We are also adding a paragraph (i) to clarify that when an operator is requesting approval of alternate procedures or equipment to the SCCE requirements under the provisions of § 250.141, the operator must demonstrate that the proposed alternate procedures or equipment provide a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well. These revisions are in response to commenters' concerns that the language as originally proposed did not clearly state a performance standard.

What are the relief rig requirements for the Arctic OCS? (§ 250.472)

Also as discussed in Sections III.B and III.D, BSEE is revising the language proposed in § 250.472 to clarify the performance standard that must be met when proposing to use alternate equipment or procedures to the relief rig requirements of § 250.472. Specifically, we are adding the phrase ''able to kill and permanently plug an out-of-control well'' to the language of proposed § 250.472(a) to clearly state the performance standards the relief rig must achieve. We are also revising the language of proposed § 250.472(c) to clarify that when an operator is requesting approval of alternate procedures or equipment to the relief rig requirements under the provisions of § 250.141, the operator must demonstrate that the proposed alternate procedures or equipment provide a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be able to kill and permanently plug an out-of-control well. These revisions are in response to commenters' requests for a clear statement of a performance standard and are designed to offer guidance and clarification to operators with respect to the performance-based standard established by this rule that any proposed alternate compliance must meet or exceed in connection with the requirements finalized in this rulemaking.

If I propose activities in the Alaska OCS Region, what planning information must accompany the EP? (§ 550.220)

BOEM is revising § 550.220(c)(6)(ii) to clarify the intent of the provision. This provision is designed to obtain information regarding the operator's relief rig plans through the EP. BOEM has revised the provision in response to comments, removing language that could potentially create confusion over the interaction between the BOEM EP informational provision and the BSEE operational relief rig requirements at § 250.472. The intent of § 550.220(c)(6)(ii) is to obtain the information that is known at the time of EP submission regarding the operator's plans for compliance with the requirements of § 250.472(b). Therefore, as a technical correction, we finalized the text of § 550.220(c)(6)(ii) without reference to ''into zones capable of flowing liquid hydrocarbons.'' This revision is explained in further detail in Section IV.B.

Technical and Clarifying Edits

The Bureaus have made several additional changes between the proposed and final regulatory text that are technical made in order to clarify edits. These changes result in more easily understandable regulations but do not make substantive changes. For this reason, the Bureaus have determined that further notice and comment is unnecessary pursuant to 5 U.S.C. 553(b).

B. Discussion of and Responses to Comments

The Bureaus divided our discussion and responses to the comments received into subject matter topics, beginning with general comments, and then organized them by section number in the order in which operators would seek to comply with the regulations during permitting and operations.

Although BSEE permitting and operational requirements appear earlier in 30 CFR part 250, with the BOEM requirements following in 30 CFR part 550, in practice the IOP and EP phases governed by the 30 CFR part 550 regulations would precede the drilling approval and oversight phases governed by 30 CFR part 250. Requirements to prepare for an oil spill, which are contained in part 254, may be met at any time before handling, storing, or transporting oil in operations BSEE permits under part 250. Consequently, the subject matter topics are presented in this preamble in the following order: Definitions of *Arctic OCS* (§§ 250.105, 254.6, and 550.105) and *Arctic OCS conditions* (§§ 250.105 and 550.105), the discussion of and response to comments on BOEM's final regulations (*i.e.,* §§ 550.105, 550.200, 550.204, 550.206, and 550.220), and then the remainder of BSEE's final regulations (*i.e.,* §§ 250.105, 250.188, 250.198, 250.300, former 250.402/finalized as 250.720, 250.418, 250.447, 250.452, 250.470, 250.471, 250.472, 250.473, and 250.1920; §§ 254.6, 254.55, 254.65, 254.70, 254.80, and 254.90).

1. General Comments

Several comments addressed general concepts related to the rulemaking, instead of specific regulatory requirements proposed in the NPRM. These commenters opposed finalizing the proposed rule for a variety of reasons including: An opposition to all drilling in the Arctic Region; the proposed regulations are unnecessary, or overly restrictive or too costly; and

the request for the proposed rule to be withdrawn and re-proposed with additional information. BOEM and BSEE respond to these comments below.

The U.S. Government Should Ban All Offshore Drilling in the Arctic Region

Many commenters opposed the proposed rule in its entirety because of their opposition to all drilling in the Arctic Region, based on concerns over climate change and other environmental reasons. Some of these commenters supported the development of renewable energy in lieu of continued exploration for oil and gas resources.

BOEM and BSEE strongly agree with the need to protect the Arctic environment, and the requirements of this final rule are an important means to achieve that goal. However, the decision whether or not to prevent the exploration and development in the Arctic OCS is beyond the scope of this rulemaking. OCSLA establishes a process for deciding when and where to issue leases based on a defined set of criteria (*see* 43 U.S.C. 1344). That is the appropriate process for deciding whether the Arctic OCS should be explored and developed, not this rulemaking.

Advancing renewable energy and transitioning away from reliance on fossil fuels is critical in the long term, but fossil fuels will continue to be an important part of the U.S.' energy portfolio for the foreseeable future. The Department is required by OCSLA to make 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). As discussed throughout this preamble, and in several studies and reports available in the docket, the development of the U.S. Arctic's significant resources has the potential to promote a greater national reliance on domestic energy resources, benefits for the U.S. economy, and enhanced global energy security. The protection of the Arctic marine and coastal environments where drilling activities take place is of the utmost importance to BOEM and BSEE. The requirements finalized in this rule ensure that current and future exploratory drilling activities on the Arctic OCS are conducted safely and responsibly, subject to strong operational requirements.

The Proposed Regulations Are Unnecessary or Overly Restrictive or Too Costly

A large number of commenters argue the regulations should not be finalized because they are unnecessary due to other Federal agencies' existing regulations. Many of these commenters also assert that the regulations are overly restrictive and will be too costly. The comments do not provide specific costs or identify specific offending provisions, but only that the regulations should not be finalized.

BOEM and BSEE disagree. The operating environment for exploratory drilling operations on the Arctic OCS is characterized by unique environmental conditions, geographic remoteness, and a relative lack of fixed infrastructure and existing operations. The provisions of this rule are necessary and appropriate to address those challenges.

BOEM and BSEE engaged in Government-to-Government Tribal consultations and Government-to-ANCSA Corporations consultations to discuss the subject matter of the proposed rule and solicit input in the development of the final rule. Additionally, many comments on the NPRM support the finalization of this rule. This rulemaking takes into account the feedback we have received from these consultations and public comments and the lessons learned from recent exploratory drilling activity on the Arctic OCS. The provisions of this final rule do not add significant burdens beyond those that BOEM and BSEE required of Shell in 2012 and 2015, as part of the conditions of approval for its EP and permits to drill. From inception to completion, every phase of Arctic OCS operations comes with inherent challenges and operational risks. BOEM and BSEE determined that the final rule is reasonable and necessary to ensure that Arctic OCS exploration is conducted responsibly and in accordance with the highest safety and environmental standards. The final regulations are also necessary to provide regulatory certainty to industry regarding the requirements BOEM and BSEE will continue to expect operators to meet in their exploration and drilling programs. This final rule provides greater certainty to partners and stakeholders that Arctic OCS operations will be undertaken with the utmost regard for safety and environmental protection. The estimated costs and benefits of the rule are analyzed in greater detail in the final RIA and discussed in the E.O. 12866 section.

The Proposed Regulations Should Be Withdrawn and Re-Proposed With Additional Information

Many commenters request the proposed rule be withdrawn in its entirety. These commenters request withdrawal based on two different rationales.

One group of commenters requested that BOEM and BSEE withdraw the proposed rule and re-propose a rule with provisions aligning with the recommendations from a study by the NPC, a Department of Energy Federal Advisory Committee, entitled, ''Arctic Potential: Realizing the Promise of U.S. Arctic Oil and Gas Resources'', (NPC Arctic Potential Study, March 27, 2015) (available at: *http://www.npcarcticpotentialreport.org/*).

We disagree with this suggestion. BOEM and BSEE participated in the development of the NPC Arctic Potential Study and used, where appropriate, knowledge gained from its development. It is our view that this final rule comprehensively addresses the challenges to prudent hydrocarbon exploration posed by the Arctic OCS's unique operating environment. BOEM and BSEE recognize the value of the NPC Arctic Potential Study as a study that considers the research and technology opportunities to enable prudent development of U.S. Arctic oil and gas resources. However, it is only one of the resources we considered in developing regulations that will ensure the safe and responsible development of petroleum resources on the Arctic OCS.

The second group of commenters recommended that BOEM and BSEE delay the finalization of this final rule until the proposed Well Control Rule was finalized.

BOEM and BSEE decided to finalize the Well Control Rule in advance of this rulemaking (*see* 81 FR 25888), although the publication of the final rule on Arctic OCS exploration in advance of the Well Control Rule would not have resulted in any conflicting provisions. Throughout both rulemaking processes, BOEM and BSEE ensured the final rule on Arctic OCS exploration and the Well Control Rule contained regulatory provisions that are consistent. The Well Control Rule applies across the entirety of the OCS, including in the Arctic OCS. Many of the provisions of the final rule on Arctic OCS exploration, however, go beyond the scope of the Well Control Rule, and respond to unique challenges posed by the Arctic OCS operating environment. Finalization of the final rule on Arctic OCS exploration, independent of the Well Control Rule, puts in place the needed systems and processes that reduce risk and provide rigorous safeguards for Alaska's North Slope coastal communities and sensitive U.S. Arctic marine environment.

2. Definitions

BOEM and BSEE proposed to add new definitions in the proper alphabetical order for *Arctic OCS* and *Arctic OCS conditions* to existing §§ 250.105 and 550.105. We received no comments on the proposed definition for *Arctic OCS conditions* and it is finalized as proposed.

BSEE further proposed to add new definitions in the proper alphabetical order for *Cap and flow system, Containment dome, District Manager, Source control and containment equipment (SCCE)* and *Capping stacks* to existing § 250.105. No comments were received to the proposed definitions at § 250.105 of *Cap and flow system, Containment dome,* or *District Manager* and they are finalized as proposed. Comments were received on the proposed § 250.105 definitions of *Arctic OCS, Source control and containment equipment (SCCE)* and *Capping Stacks.* One commenter requested the final rule include a definition for MODU.

Arctic OCS

Three commenters requested BOEM and BSEE refine the proposed definition of ''Arctic OCS'' in §§ 250.105 and 550.105 to include more than the Beaufort and Chukchi Sea Planning areas. Two of these commenters suggested utilizing all OCS areas north of the Arctic Circle under U.S. jurisdiction as the ''Arctic OCS''.

BOEM and BSEE disagree that the ''Arctic OCS'' should be redefined to include offshore areas beyond the Beaufort Sea and Chukchi Sea Planning Areas. We determined that the final definition in this rulemaking should align with the areas of the Arctic OCS utilized in the DOI OCS Oil and Gas Leasing Program for 2012–2017 (June 2012, available at *http://www.boem.gov/Five-Year-Program-2012-2017*). The Arctic OCS definition is reflective of the conditions and challenges the rule is designed to address, and allows focus on Planning Areas with higher hydrocarbon potential. Any other details added to this definition would increase confusion over the scope and applicability of the rule.

SCCE

One commenter stated the proposed definition of SCCE in § 250.105 excludes some of the primary intervention options, such as injection as a means to secure the well. The commenter recommended the definition for surface devices should include pumps and injection lines for dynamic kill and injection into well, and reference to subsea equipment should include jumpers, manifolds, and associated equipment to facilitate pumping into the well.

BSEE disagrees and has chosen to include as SCCE equipment only the equipment necessary to regain control of a well when the primary systems fails and that is not used in everyday drilling operations. Standard equipment (such as the BOP) is specifically excluded from the definition as it is a requirement of safe drilling operations regulated in other provisions of BSEE's rules. The definition of SCCE is not intended to be exclusive or restrictive, nor is the requirement that operators possess and have the ability to promptly deploy such equipment intended to preclude the use of other intervention mechanisms not specifically mentioned.

Capping Stacks

One commenter noted the proposed definition for capping stacks in § 250.105 limits the use of pre-positioned capping stacks to subsea wellheads when surface BOPs are used. The commenter suggests that the definition should be expanded to allow pre-positioned capping stacks to be used below subsea BOPs when deemed technically and operationally appropriate, such as with a jack-up rig.

BSEE agrees that pre-positioned capping stacks should be included in the definition. We therefore added the language ''including one that is pre-positioned'' to the definition for Capping Stack in § 250.105. BSEE will evaluate the use of a pre-positioned capping stack as a part of an operator's proposal on a case-by-case basis and approve their use below subsea BOPs when deemed technically and operationally appropriate, such as when an operator proposes to use a jack-up rig with surface trees.

MODU

One commenter requested a definition of MODU be included in the final rule.

BSEE disagrees. There is no one comprehensive definition of a MODU that can be utilized across parts 250, 254 and 550. MODUs include different types of vessels, including floating facilities or jack-up rigs, capable of engaging in well operations (*e.g.,* drilling, well completion and workover activities) for the purpose of exploring for or developing subsea oil, gas, or sulfur resources or related activities. What is considered a MODU may vary based on the activity being regulated. These regulations address only MODUs used for exploratory drilling, which include floating drilling vessels and jack-up rigs.

3. Additional Regulations by BOEM

Definitions (§ 550.200)

BOEM proposed to insert the acronym *IOP*—meaning Integrated Operations Plan—into the proper alphabetical location within existing § 550.200, for purposes of the IOP provisions. No comments were received on this provision and it is finalized as proposed.

When must I submit my IOP for proposed Arctic exploratory drilling operations and what must the IOP include? (§ 550.204)

BOEM proposed new § 550.204. This section requires operators to develop and submit IOPs to BOEM at least 90 days in advance of filing their EPs. The purpose of the IOP is to describe, at a strategic or conceptual level, how exploratory drilling operations will be designed, executed, and managed as an integrated endeavor from start to finish. The IOP is intended to be a concept of operations that includes a description of pertinent aspects of an operator's proposed exploratory drilling activities and supporting operations and how the operator will design and conduct its program in a manner that accounts for the challenges presented by Arctic OCS conditions. Several comments were received on this section. To clearly address the commenters' concerns, we have organized our discussion of § 550.204 in two separate topics: (i) Information requested for IOP completion, and (ii) appropriateness of IOP submission. BOEM has reviewed the comments and determined to finalize § 550.204 as proposed for the reasons stated herein.

Information Requested for IOP Completion

Many commenters generally criticized the IOP provision as being duplicative or redundant of existing requirements.

BOEM disagrees. The IOP rules are neither redundant nor duplicative of existing requirements. The IOP is meant to be an overview of all phases of the operator's proposed operations in order to allow the Federal agencies an earlier review in the planning process than currently exists. Section 550.204 requires a description of the design and operation of the proposed exploratory drilling program that demonstrates the operator is accounting for Arctic OCS conditions. Using this description, Federal agencies will coordinate and reduce potential delays by identifying possible vulnerabilities early in the planning process related to safety and environmental protection. This proactive approach enables the operator

to address these issues more effectively in the EP. Though BOEM would review the IOP to ensure that the operator's submission includes each of the elements listed in § 550.204, the IOP would not require approval by DOI or the other relevant agencies. Accordingly, the IOP is fundamentally distinct from the EP. First, the provisions of OCSLA that govern the EP do not apply to the IOP in that the EP requires an agency decision while the IOP is reviewed to ensure the submission is complete. Second, the operator's IOP will contain planning information with less specificity than that furnished with the EP.

Given the important role played by contractors and the fact that many contractors hired to operate on the Alaska OCS do not have a long operating history in the region, effective contractor oversight by operators is critical, and sufficient oversight of each contractor can be a challenge. Section 550.204(f) requires operators to plan for how they will manage contractors to reduce operational risks and address the challenges associated with operations on the Arctic OCS. Further, § 550.204(b) requires operators to plan to coordinate the work of a number of contractors to ensure that time pressure or other contractor complications do not undermine safe and environmentally responsible operations. This section requires a degree of advanced planning that should identify critical paths necessary for successful operations, ensure requisite resources are allocated, and mitigates risks through adequate forethought.

Additionally, if an operator determines that information it will submit in an EP is redundant with that submitted in an IOP, § 550.201(c) provides the Regional Director discretion, on a case-by-case basis, to waive submission of required information or analyses when sufficient applicable information or analyses are readily available to BOEM. Paragraph (d) of § 550.201 also allows for referencing other pre-existing information and data when submitting an EP if that information was previously submitted or is otherwise readily available to BOEM, thus allowing the IOP to simplify the EP preparation process.

Another group of commenters asserted that information required to be included in the IOP will not always be available 90 days before the EP submission. One of the commenters explained that much of the operator's data is immature during this planning phase.

BOEM acknowledges that the IOP will be submitted at a phase of the planning process when not all details of proposed operations will be in place, and that such details will necessarily be further developed through later stages of the process. While the operator will explain how exploratory activities will be integrated in its IOP, BOEM does not expect the IOP to exhibit the same level of detail that other documents (*i.e.* EP, APD, and OSRP) contain. For example, § 550.204(f) requests the operator to list the work its contractors will perform, but does not require the operator to have selected a specific contractor at the time of IOP submission. By providing that the operator need not have finalized contractor selection, it is reasonable for the IOP to be completed, at a minimum, 90 days before the submission of the EP.

The operator should already have the information required to complete an IOP 90 days prior to submitting an EP due to the advanced planning necessary for the operator to safely operate in Arctic conditions and minimize its effects on local communities. In addition, the operator must perform detailed engineering themselves or have a contractor do such work, well in advance of the open-water season. Further, if the operator does not have the general summary information for the IOP, then it is unlikely that the operator will be in a position to submit a completed EP 90 days later.

Another of the commenters requested that BOEM provide notice to the State and local governments when it receives an IOP.

Regarding this request, we note that in addition to posting the IOP online, § 550.206(a)(2) requires the operator to submit eight copies to BOEM for public distribution. BOEM will share copies with State and local governments.

Several commenters requested clarification on whether an operator is obligated to respond to requests for additional information (RFAI) from BOEM, BSEE, or the other agencies with access to the IOP. The commenters note that if operators are obligated to respond to such requests, associated review timings should be established to ensure operators receive feedback within 45 days of submission.

The IOP will be circulated among the members in the E.O. 13580 Alaska Energy Permitting IWG, whose membership and function are discussed in Section I.B, and other relevant agencies. Members of the working group and other agencies will dialogue with the operator about any aspects of the proposed operations that may create risks. This dialogue ensures the operator is aware of elements of its proposed operations requiring clarification or revision to obtain later regulatory approvals in a manner consistent with each agency's regulatory requirements. The IOP is an informational document that must be filed and should cover the identified elements, but does not require approval by DOI. If all elements of § 550.204 are not addressed by the operator in its IOP, BOEM may request supplementation from the operator.

BOEM does not agree that the regulations should be amended to add a 45-day limit for when BOEM's feedback on the IOP should be sent to an operator after the operator has submitted its IOP. If the operator is unable to provide supplementation related to feedback given by BOEM before the end of the IOP review period, the operator would be able to furnish the material in its EP submittal. If, however, during an early point in the review period, BOEM finds that the operator's IOP is incomplete in such a way that it does not address all of the elements of § 550.204, then it may request that the operator supplement the incomplete IOP submission.

One commenter requested clarification of the need for ''sufficient information'' when submitting the IOP description of vessels utilized in the operator's proposed exploratory drilling program. The commenter understands this as the IOP requirement effectively establishing a 120 day review period for proposed operations (90 days for the IOP and 30 days for the EP). The commenter stated this mandatory IOP process will effectively delay EP submissions and ultimately frustrate future drilling efforts.

BOEM disagrees with the assertion that the IOP will delay the EP process, or that the IOP is designed to effectively expand that process. The final rule is a combination of prescriptive and performance-based requirements developed after extensive outreach to stakeholders, operators, and government agencies. BOEM will review the IOP for completeness, and if the agency finds that aspects of the operator's plan do not meet the necessary information obligations of § 550.204, then it will request the information be presented. The IOP is not subject to approval, and should not delay submission of the EP. Because the IOP is an overview that requires less detail than the EP, operators will be in a position to submit the IOP earlier in their planning process than the EP itself. As a result, the 90-day period will not delay the submittal of the EP.

Three commenters commented on the frequency of IOP submissions. One commenter requested clarification on whether a single IOP could address

multiple EPs. Another commenter requested that BOEM consider a single IOP filed prior to an operator's first EP. The third commenter suggests the IOP be updated when an EP is updated.

BOEM disagrees that an IOP will need to be updated whenever an EP is updated. An IOP is required for each exploratory drilling program planned by an operator. However, a single IOP may cover multiple EPs when sufficient geographic and operational overlap exists. The IOP serves its primary purpose before an EP is submitted, as it informs the early planning process prior to initial EP submission. Requiring the IOP to be updated after the EP's submission would not serve any practical purpose, because the EP serves as the main point of reference for both agencies and the operator after the EP is filed.

One commenter recommended the IOP should mirror the International Association of Oil and Gas Producers (IOGP)/International Petroleum Industry Environmental Conservation Association (IPIECA) guidelines for oil spill risk assessments and management plans.[10] BOEM disagrees with this comment. The IOGP/IPIECA guidelines far exceed the expected scope of the IOP. The IOP is a conceptual document that holistically addresses an operator's Arctic OCS drilling operations from start to finish, providing regulatory agencies a preview of an operator's approach to regulatory compliance and integrated planning. The IOP does provide information on advanced preparations and staging of oil spill response assets, necessary for both BOEM's environmental impact analysis and for BSEE's overall understanding of the operator's OSRP. BOEM does not believe that the final regulations require amendment in response to these comments.

One commenter requested that IOP provisions should require proposed mitigation measures to avoid conflicts with subsistence activities. BOEM does not think this is necessary, as BOEM has determined that existing requirements address this concern. Before an EP is approved, BOEM must comply with applicable statutory requirements to analyze the potential impacts of the proposed exploration activities. As part of the analyses, BOEM analyzes how mobilization, demobilization, and exploratory drilling could affect subsistence use, resource use, and harvest activities. Both BOEM and BSEE may require additional mitigation measures at the EP and APD stages, as necessary, to address appropriately potential interference with subsistence activities. For example, because subsistence hunters are concerned that the effects of offshore oil and gas exploration might displace migrating bowhead whales and other marine mammals (like beluga whales), the Bureaus will meet with the Alaska Eskimo Whaling Commission and its whaling captains to help document traditional knowledge pertaining to bowhead whales, including movement and behavior. Given the importance of subsistence activities and related socio-cultural activities to the Alaska Native communities, operators are encouraged to work directly with interested parties to help mitigate potential impacts to subsistence activities. In addition, BOEM will continue to fund and support studies to better understand the potential impacts from OCS operations on marine mammals and subsistence activities.

One commenter asserted that the proposed rule failed to address public and private investment in on-shore infrastructure supporting oil spill response and protection of specific lands and resources. The commenter noted that the proposed rule neglected local community involvement in oil spill response capabilities, especially at Point Lay, the local community most likely to be impacted by the oil spill response activities. The commenter suggested that regulation be written to specifically require onshore infrastructure development at Point Lay and Cape Sabine, both former Distant Early Warning Line radar sites with existing, but unutilized infrastructure. The commenter shared his Kali traditional knowledge of local meteorological conditions with BOEM and BSEE personnel and has noted that weather conditions often times permit safe flight operations from Point Lay when they are suspended in Barrow and Wainwright.

BOEM has determined that both existing regulations and regulations finalized in this rulemaking address the commenter's concern regarding community involvement. Section 550.202 mandates that operators plan and prepare to conduct their proposed activity safely in conformance with all applicable legal requirements and sound conservation practices in a manner which neither unreasonably interferes with other OCS uses nor causes undue or serious harm to the human, marine or coastal environment. Additionally, § 550.204(j) requires the operator to include in its IOP a description of whether and to what extent a project will rely on local community workforce and spill cleanup response capacity. Regarding the request for specific onshore infrastructure investments, BOEM cannot in this rulemaking specify the location of such investments.

Two commenters assert that introducing an IOP prior to the EP is impractical and unnecessary in terms of timing and objectives. One commenter recommended the submittal of the EP should continue to precede the IOP to allow timely exploration to occur while the IOP is being developed. The commenter argued there is a lack of efficiency in asking operators to prepare a complete IOP as a pre-requisite to engaging in meaningful project-related dialogue and that early engagement between operators and the Federal agencies would be more meaningful as an iterative pre-application process that feeds into the IOP. The second commenter proposes the removal of the IOP as a separate document and that the EP and APD processes are adapted and clarified to meet the intentions of the IOP requirement.

BOEM disagrees and has determined to finalize the IOP provisions as proposed. The IOP requirement calls for information that is different from what is required to be provided in an EP or an APD. Information in an IOP contains a different level of detail and is required at a different point in the planning process. By requiring an IOP, the entire planning process should become more efficient by decreasing the likelihood of requests for additional information or plan modifications during the later stages that require approval. The early engagement facilitated by the IOP requirements of § 550.204 should increase efficiency by improving communication between agencies and operators, improving early agency understanding of and operator preparedness for planning activities.

Appropriateness of IOP Submission

Several commenters assert that the requirement to submit an IOP 90 days before submitting an EP for Arctic exploratory drilling operations is inconsistent with the OCSLA requirements at 43 U.S.C. 1340(c), and the Department is improperly exceeding its jurisdiction by requiring submission of the IOP information. Two of the commenters also assert that the IOP would require reporting of information and data beyond DOI's scope of jurisdiction and is not based in any statutory authority granted by Congress.

[10] The International Association of Oil and Gas Producers (IOGP) is an association, formed in 1974, whose members include public, private, and state-owned oil and gas companies and upstream service companies. The International Petroleum Industry Environmental Conservation Association (IPIECA), formed in 1974, is a global oil and gas association addressing environmental and social issues.

BOEM disagrees. The OCSLA requires the submission and approval of an EP, but does not specify or restrict what other information BOEM may require before the EP is submitted. The OCSLA provides the Secretary authority to require information described in the IOP. Section 1334(a) of Title 43 of the U.S.C. grants the Secretary authority to ''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].'' Section 1332(6) declares that: ''operations in the [OCS] should be 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, spillage, 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.'' [11]

Section 1348 of Title 43 of the U.S.C. imposes a duty on lessees and operators to ''maintain all operations . . . in compliance with regulations intended to protect persons, property, and the environment on the [OCS].'' [12] The ability of lessees to explore for oil and gas on the Arctic OCS in accordance with these statutory mandates depends on early, integrated planning. This planning necessarily implicates activities, such as the operation of vessels which are regulated by other Federal agencies but also inform and influence the Department's oversight functions. For example, while the Department does not directly regulate the operations of vessels carrying capping stacks to Arctic well-sites, ice-management vessels or vessels responsible for towing rigs, lessees cannot safely conduct exploratory drilling without properly planning for these activities. Such activities can result in damage to operational equipment critical to DOI-regulated drilling activities, which can in turn compromise, reduce, or force modifications to approved operational or safety capabilities and equipment. Similarly, they can give rise to changes to approved operational schedules, which in the Arctic are particularly critical in light of the limited open water season, the timing of recession and encroachment of sea ice at drill sites, marine mammal migrations, and subsistence hunting seasons, among other considerations.

The EP and the IOP serve different purposes and are not governed by the same provisions of OCSLA. The EP is a statutorily mandated submission under 43 U.S.C. 1340(c), approval of which is required prior to exploration of any OCS lease. BOEM regulations set forth comprehensive and detailed requirements for the contents of an EP.[13] BOEM carefully scrutinizes submitted EPs to ensure that they satisfy all applicable requirements, are consistent with lease terms and governing law, and would not cause serious harm or damage to life, property, any mineral, national security or defense, or the marine coastal or human environment.[14] EPs also provide the basis for analyses and determinations required by other Federal laws, as well as subsequent BSEE review and approval of APDs. Upon satisfaction of all applicable requirements, BOEM approves an EP, often subject to conditions; the terms of that approval are binding and govern activities conducted pursuant to the EP.

The IOP is fundamentally distinct from the EP, and does not implicate the section of OCSLA that governs EPs, 43 U.S.C. 1340. The IOP will be required to be submitted to BOEM well in advance of the EP, at a time when the Department recognizes the operator might not possess the type of detailed and specific information that is required to obtain approval of an EP. It requires Arctic-focused conceptual planning information to encourage and facilitate the development of integrated operational strategies early in the planning process. While the IOP will be reviewed to ensure that the submission is complete, addressing each of the elements listed, the IOP is not subject to approval by any Federal agency and does not bind the operator's future activities. Rather, the IOP, unlike the EP, is designed to be a preliminary informational resource to facilitate relevant Federal agencies' early familiarity with, and opportunities for constructive feedback on, important concepts related to the design of an operator's planned exploration program in an integrated manner that accounts for the unique Arctic OCS conditions. This process has the potential to facilitate the later EP review, but it is fundamentally distinct from the EP itself.

Agency regulations have long recognized the need to obtain through the planning process information about activities outside of the Department's direct regulatory jurisdiction but which are clearly relevant to approval of operations within our jurisdiction.[15] OCSLA provides the Secretary with the authority to require information necessary to ensure that Arctic OCS operations are safe and environmentally responsible and to help facilitate early review by the Department and other agencies in advance of the EP. 43 U.S.C. 1334(a). The IOP requirement reflects a reasonable exercise of that authority.

Section 1340(c) of OCSLA requires lessees to submit an EP for approval before they commence exploration pursuant to their lease, and it requires BOEM to take action on an EP within 30 days after submission.[16] The 30-day time limit for reviewing an EP begins only after BOEM's Regional Supervisor deems the EP submitted.[17] This statutorily mandated regulatory requirement is specific to EPs and does not affect the authority in OCSLA to require the preliminary informational submission of the IOP.

One commenter argued that industry should not have to incur the additional cost of an IOP considering the roughly 124 day drilling window in the Chukchi Sea, and that the 90 days could instead be spent by agencies to integrate their services for regulatory efficiency. The commenter asserted that agencies must start working together to streamline the regulatory process, to fund and support Arctic-centric science, and to support infrastructure development in this remote region of the country.

We agree with the commenter's concern for agency integration and note the key purpose of the IOP is to facilitate interagency coordination on matters of mutual interest. The regulatory oversight of the Arctic OCS is shared by many agencies and the need for integration among them is recognized by the establishment of the E.O. 13580 Alaska Energy Permitting IWG. The E.O. 13580 Alaska Energy Permitting IWG consists of representatives from Federal agencies which include DOI, the Departments of Defense, Commerce, Agriculture, Energy, Homeland Security, and the EPA. BOEM will circulate the IOP amongst the aforementioned agencies;

[11] *Id.* at section 1332(6).

[12] *Id.* at section 1348(b)(2).

[13] *See* 30 CFR 550.211 through 550.228.

[14] *Id.* at §§ 550.202, 550.233.

[15] *See, e.g.,* § 550.224 (requiring description in EP of the support vessels, offshore vehicles, and aircrafts you will use to support your exploration activities, including maps of travel routes and methods for transportation of fluids, chemicals, and wastes); § 550.257 (same for Development and Production Plans (DPPs) and Development Operations Coordination Documents (DOCDs)); § 550.225 (requiring description in EP of onshore support facilities to be used to provide supply and service support for the proposed exploration activities); § 550.258 (same for DPPs and DOCDs).

[16] 43 U.S.C. 1340(c).

[17] *See* 30 CFR 550.233.

such circulation and familiarity will result in a more collaborative effort in regulating OCS oil and gas exploration. With respect to the commenter's concerns regarding timing, the requirement to submit the IOP should not impact the length of the available drilling season as the IOP may be submitted well in advance of the open-water season. With respect to costs, those issues are analyzed at greater length in the final RIA. However, we note here that the type of planning reflected in the IOP is essential for the successful execution of any Arctic OCS exploratory drilling campaign, so the only costs associated with the requirement should be the limited costs of assembling those plans for submission.

How do I submit the IOP, EP, DPP, or DOCD? (§ 550.206)

BOEM proposed to revise § 550.206 to include information that explains how operators should submit their IOPs and allowing operators to request the nondisclosure of information in the IOP using established DOI processes. As is currently the case with EPs, Development and Production Plans (DPPs), and Development Operations Coordination Documents (DOCDs), operators requesting the nondisclosure of portions of an IOP should provide BOEM with two separate versions of the IOP; a public version from which potentially exempt information is redacted, and an agency version with such information present, but clearly marked as proprietary.

Several comments were received on this section. BOEM has evaluated these comments and decided to finalize § 550.206 as proposed. Two commenters requested that BOEM require planning information be submitted electronically to allow immediate availability for public access. This requirement would allow BOEM to immediately upload public-information copies of EPs and IOPs without the intermediate step of reformatting the operator's submissions.

We determined electronic submittal should remain optional. Currently, DOI allows electronic submittals of all or part of the EP and the final rule will allow electronic submission of all or a portion of the IOP. Whether the information is received electronically or in the form of a hardcopy, BOEM will post the appropriate information on *http://www.boem.gov/alaska-region/.* If documents are not received electronically, BOEM will take the necessary steps to convert the files to a format compatible for online viewing by the public.

One commenter recommended that EP requirements be updated to require liaison with DOI as soon as the planning process starts, in order to coordinate forward planning and keep authorities abreast of the approach and milestones related to the EP. The commenter recommended the regulations be revised to require the EP scope be reviewed to ensure that it includes appropriate information requirements related to planning of integrated operations and how this will be achieved. The commenter goes on to recommend that these issues will be discussed as part of the overall EP development process, and that the APD scope be reviewed to ensure that it includes specific requirements for documentation of planned integrated operations, including finalized vessels, contractors and associated management systems. The commenter stated that by establishing such an approach, along the lines of approaches taken by the United Kingdom, Norway, Australia and others, the process for documenting selection and suitability of a rig would be simplified, enabling focus on other risk elements relating to how the unit will be utilized in integrated operations.

BOEM has determined the commenter's recommendations are addressed in the finalized provisions at § 550.204. Compliance with the provisions of § 550.204, related to the submission of the IOP, allows for operators and DOI to coordinate early in the planning process, and allows early visibility and opportunities to address how an operator's activities will be conducted in an integrated manner.

One commenter requested to receive a copy of all Arctic OCS applications and be provided with at least 30 days to review and comment on the applications.

BOEM's existing regulations allow for the public to review and, as appropriate, allow for comment from State, municipal and tribal governments. As stated in the NPRM, BOEM intends to post public versions of IOPs to its Web site upon receipt. Once an EP or DPP is deemed submitted, it is posted on BOEM's Web site, *http://www.boem.gov/alaska-region.* Additionally, § 550.232, *What actions will BOEM take after the EP is deemed submitted?,* allows the Governor of each affected State 21 calendar days to submit comments. During this time, BOEM will make the EP available for public review and comment. Section 550.267, *What actions will BOEM take after the DPP or DOCD is deemed submitted?,* provides that BOEM will make the DPP publicly available within 2 business days of deeming it submitted and accept comments for 60 days after making it available to the public. BOEM has determined these efforts toward public engagement are adequate. BOEM also notes that, particularly with respect to EPs, additional time for public engagement is statutorily constrained.

One commenter recommended that DOI conduct timely and meaningful consultation with Alaska Native tribes before approving an EP. BOEM agrees. Consistent with E.O. 13175 (Consultation and Coordination with Indian Tribal Governments) and Secretarial Order 3317, BOEM requests Government-to-Government consultation with Alaska Native tribes for which the exploration activities could have tribal implications. The Department is committed to fulfilling its tribal consultation obligations, whether directed by statute or administrative action such as E.O. 13175, or other applicable Secretarial orders or policies.

One commenter requested clarification in the final regulations that evidence of equipment ownership or contracts with equipment providers is required only for an APD, but not required for approval of an EP or an OSRP. The commenter expressed concern with having to make commercial commitments to very expensive equipment contracts before getting confirmation from the Bureaus that the plans based on that equipment would be approved. The commenter stated there is sufficient time after EP and OSRP approval for the operator to procure equipment that conforms to the approved plan, and to provide evidence of such procurement at the APD stage.

BOEM does not believe that the final regulations require amendment in response to this comment. Both existing regulations and this final rule require varying levels of information about operator safety and oversight management at progressive stages of the planning and approval process. This information would begin with general information and narrow down to increasing levels of detail with successive regulatory submittals, as the project proceeds from planning to implementation. For example, at the IOP stage, we recognize that operators may not have contracts for vessels finalized or precise dates of drilling so, accordingly, specific names of contractors are not necessary, but could be provided if available. At the EP stage, § 550.220(c) requires, among other planning information, a preliminary general description of SCCE and relief rig capabilities needed for compliance with §§ 250.471 and 250.472. BOEM anticipates that the relief rig description may be general at the EP stage, but

detailed enough for BOEM to confirm that the operator has plans in place for how it would conduct its operations safely and in compliance with the regulations. Further, existing regulation § 550.211(c) requires that a description of the drilling unit and associated equipment be provided in the EP along with a brief description of its safety and pollution prevention features, type of fuel, and an estimate of the maximum quantity of oils, fuels and lubricants. Existing regulation § 550.224(a) also requires at a general level a description of crew boats, supply boats, anchor handling vessels, ice management vessels, aircraft, and other vessels. These longstanding requirements, as supplemented by this rule, lay out a clear picture of the type and level of detail required at different stages of the approval process that is both achievable and appropriate for the management of these operations.

If I propose activities in the Alaska OCS Region, what planning information must accompany the EP? (§ 550.220)

BOEM proposed to revise several of the existing provisions at § 550.220 to ensure, through thorough advanced planning, that operators are capable of operating safely in the extreme and challenging conditions of the Arctic OCS. Revisions to the section include amending the existing ''Emergency Plans'' provision at § 550.220(a) to add fire, explosion, personnel evacuation, and loss of well control to the events for which emergency plans are required, and to replace the terms ''blowout'' with ''loss of well control'' and ''craft'' with ''vessel, offshore vehicle, or aircraft'' for clarification purposes. Finally, BOEM proposed creating a new § 550.220(c), which would set forth additional information requirements for EPs that are proposing exploration activities on the Arctic OCS.

Several comments were received on the provisions in this section. BOEM has reviewed the comments and determined to finalize § 550.220 as proposed for the reasons stated herein. One technical revision is finalized at § 550.220(c)(6)(ii). As discussed above in Section IV.A, this revision is required to correctly align the provision with the relief rig planning requirements of § 250.472. For a full discussion of the comment and our response, see the discussion of § 250.472 in Section IV.B.

Two commenters recommend that the end of season date should be decided by the regulators and not by the operators, and also that the operator should only be allowed to drill into hydrocarbon zones with enough time to complete a relief well and remove oil before the freeze-up date. One commenter expressed concern that the operator may overstate their relief well capabilities in order to maximize the length of their drilling season.

BOEM agrees with the commenters. To clarify, the end of season dates that the operator proposes in its EP are anticipated dates. BOEM, in consultation with the NWS, will analyze past and present meteorological conditions, oceanic conditions, and sea ice concentration and movement to determine if the operator has provided an appropriate end of season date estimate to account for its own unique operational capabilities and limits. BOEM does this through the establishment of the trigger date, or estimated seasonal ice encroachment date, that sets a deadline on when the operator can drill or work on the surface casing, so that risks associated with late season drilling are addressed and response and cleanup activities can occur in a timely manner.

Two commenters strongly supported the imposition of an end of season date for operators and request removal of the word ''anticipated'' in § 550.220(c)(6) to ensure that Arctic OCS operators provide a firm date for their end of seasonal operations to avoid increased risks associated with freeze-up. The commenters further recommended that the final rule provide the Bureaus authority to require operations to terminate before these dates if actual conditions during the drilling season indicate earlier likelihood of ice encroachment over the drill site. The commenters suggest these dates should undergo scientific review by the relevant agencies and should be based on at least ten years of historical ice and weather data.

BOEM disagrees with removing the word ''anticipated'' from the provisions of § 550.220(c)(6). There are two dates an operator must address in this provision when onsite operations will be complete and when drilling operations will terminate. These dates retain some flexibility at the EP stage, as they are based on a number of predictive factors related to the operator's capabilities to mitigate risk in operating on the Arctic OCS and to the prevailing meteorological and oceanic conditions that vary from year to year. Many of the provisions finalized in this rulemaking require the operator to provide BOEM and BSEE pertinent information that may require exploratory drilling operations to terminate at an earlier date than anticipated at the EP stage. For example, § 250.188 requires the operator to report to BSEE information on various incidents, including sea ice movement that may affect operations or trigger ice management activities and any unexpected ''kicks'' or operational issues that could result in the loss of well control. We further note the anticipated end of season dates are reviewed through interagency and scientific review prior to an approval of an EP.

Two commenters recommended adding to the final rule a provision requiring operators to develop, as part of the EP, a detailed written Oil Spill Prevention Program that includes a training program. One of the commenters suggest the prevention plan should address critical oil spill prevention programs such as blowout preventer testing, well control, corrosion monitoring and control programs, maintenance and testing of leak detection systems and alarms, and other prevention work.

BOEM and BSEE disagree. Oil spill prevention is a common theme among BOEM and BSEE regulations with the end goal being to prevent serious harm or damage to life, property, any mineral, national security or defense, or the marine, coastal or human environment. As planning is an essential part of spill prevention, the finalized provisions at § 550.220(a) mandate that the operator describe its emergency plans for responding to a variety of incidents, including a loss of well control, at the EP stage. Similar requirements at existing § 550.213(g) require the operator to discuss its worst-case blowout scenario in the EP, including options for response, such as surface intervention and a relief well. Further, existing regulations at § 550.219 mandate that the operator submit an OSRP in accordance with BSEE requirements in part 254, including the training requirements set forth in § 254.29. Accordingly, the Bureaus do not believe that the proposed revisions to § 550.220 are necessary or appropriate.

One commenter recommended deleting § 550.220(a) as existing regulations require a description of plans in the event of a loss of well control, the loss or disablement of a drilling unit, and the loss or damage to support craft, and the proposed language requires information concerning emergency plans in the event of 'fire, explosion, or personnel evacuation'. The commenter explains that this information is currently captured by Emergency Evacuation Plans drafted for each of its drilling units and submitted to the U.S. Coast Guard (USCG) pursuant to 33 CFR 146.210. The commenter requested

BOEM incorporate these documents by reference and not require the information to be submitted multiple times across agencies.

BOEM disagrees. Drilling operations, especially in the Arctic OCS, are subject to operational risks and environmental challenges during every phase of the endeavor. For the most part, the text of § 550.220(a) remains unchanged from longstanding requirements. To the extent that operators have compiled the relevant information for other purposes, the burdens of providing them for the EP are minimal and may potentially be addressed through reference on a case by case basis.

One commenter stated the information requested in § 550.220(c)(1) is unnecessary and repetitive, as existing § 550.211 already requires a detailed description of drilling activities and this same information is also requested as part of the IOP under § 550.204.

BOEM disagrees that § 550.220(c)(1) is unnecessary and repetitive, as existing § 550.211 sets forth general requirements for what must be included with an operator's EP anywhere on the OCS. Because of the unique operating environment of the Arctic OCS, proposed activities in this region are subject to additional levels of scrutiny and specialized requirements. Section 550.220(c)(1) is addressed directly to that need, calling for descriptions of the suitability of proposed operations for Arctic OCS conditions, in contrast to the more generic requirements of § 550.211. Additionally, as explained in previous responses to comments, the operator's plans furnished with the IOP are less detailed than the information later available and required for submission with the EP, providing an opportunity for elaboration based on new information as it comes available.

One commenter is supportive of resource sharing with other operators, provided that appropriate terms and agreements can be made. However, the commenter asserted the requirement to share these proprietary private-party agreements under § 550.220(c)(5) is not appropriate and opposes the attempt to regulate what resources will be shared and with whom. The commenter asserted that involvement in any resource sharing agreements will not affect the operator's ability to meet the regulatory requirements regarding oil spills and emergency planning.

BOEM disagrees with the commenter's characterization of the regulation and clarifies that § 550.220(c)(5) is not an attempt to mandate resource sharing by regulation. Instead, this is a requirement to inform BOEM about any agreement the operator may have with a third party for sharing of assets or provisions for mutual aid in the event of an oil spill, as applicable, so regulators are aware of what response resources are available to an operator in the event of a loss of well control. This information is critical to ensure that the operator has made the necessary arrangements to respond appropriately in the event of a loss of well control incident. This information is also critical to confirm the operator's compliance with the relevant regulatory requirements related to well control equipment. To the extent that operators rely on such arrangements to satisfy their regulatory obligations, it is essential for the Bureaus to have access to the terms and conditions of those arrangements to confirm compliance. Additionally, the operator is required under this final rule at § 250.470(f)(1) and (3) to demonstrate at the APD stage that its membership agreements with cooperatives, service providers or other contractors include 24-hour per day availability of SCCE or related supplies while it is drilling or working below the surface casing. The operator is also required to describe its or its contractor's ability to access or deploy all necessary SCCE in accordance with § 250.471 and the SCCE listed in its EP. It is the operator's responsibility to ensure that reliance on resource sharing arrangements does not compromise its ability to fully and promptly respond to an event, and the required information is important to the bureaus' ability to ensure that this is addressed. We note that proprietary information is protected in accordance with existing §§ 250.197 and 550.197, *Data and information to be made available to the public or for limited inspection.*

One commenter asserted that the anticipated end of season dates as described in § 550.220(c)(6) should not be driven by a specific calendar date, but by the application of performance-based principles including the ability of the operator's equipment, procedures, and expertise to effectively manage and mitigate risks that are reasonably likely to occur.

BOEM notes that the end of season dates discussed in the final rule at § 550.220(c)(6) are developed largely based on the capability of the operator's equipment and procedures to manage and mitigate risks associated with Arctic OCS conditions. Any date established depends on a number of factors, including a trigger date set by the Bureaus based on an evaluation of earliest sea ice encroachment, the latest ice and weather forecasts, the prevailing meteorological and oceanic conditions, and the timeframe in which an operator could drill a relief well. The specific calendar date is calculated using a performance-based metric, allowing for the operator to apply its capabilities and expertise in reaching a specific date, as approved by the Bureaus.

One commenter recommended deleting the entirety of § 550.220(a), (c)(3), and (c)(4) and replacing them with more performance-based requirements. Specifically, the commenter suggests that the EP be required to contain general planning information on source control and containment capabilities, including anticipated location and mobilization/demobilization times of equipment to mitigate risk from a loss of well control incident.

BOEM disagrees and is finalizing these sections as proposed. One of the main goals of this rulemaking is to help ensure, through advanced planning, that operators are capable of operating safely in the extreme and challenging Arctic OCS conditions. This rulemaking amends existing § 550.220(a) to add fire, explosion, and personnel evacuation to the events for which emergency plans are required and to replace the terms ''blowout'' with ''loss of well control'' and ''craft'' with ''vessel, offshore vehicle, or aircraft'' for clarification purposes. Paragraph (a) of § 550.220 otherwise remains unchanged from its longstanding form, and keeps the development of emergency plans largely within the performance-based control of the operator. Paragraphs (c)(3) and (4) of § 550.220 simply require the operator to provide a general description in its EP of how it plans to satisfy the separate operational requirements imposed by BSEE at §§ 250.471 and 250.472. While the operator has flexibility in determining how it will comply with those requirements, making the required EP description of the operator's compliance plans more general or performance-based would be unnecessary and inappropriate, and would not satisfy the Bureaus' need to ensure appropriate planning for compliance with the regulations.

One commenter requested that the requirement to provide some data for the APD be accelerated to the EP, including more information to account for operations in Arctic OCS conditions; more detail on emergency and critical operation curtailment plans; a detailed description of how the drilling rig, relief well rig, SCCE, support vessels and other associated support equipment and activities will be designed and conducted in a manner that accounts for Arctic OCS conditions; and information regarding operators' capabilities for

preventing, controlling and/or containing a WCD. The commenter also recommended the IOP be included in the EP application as an appendix and be subject to public review and comment.

Both existing regulations and the regulations finalized in this rulemaking require varying levels of information at progressive stages of the planning and approval process. Furthermore, this final rule contains a combination of prescriptive and performance-based requirements that address a number of important issues. The required submissions begin with general information and are followed by more specificity with successive regulatory submittals, as the project proceeds from planning to implementation. The IOP is an overarching, high-level description of the integration of the exploration activities that provides an advanced summary of all phases of the proposed operations for the relevant Federal agencies to review and is designed to enable Federal agencies to identify possible vulnerabilities early in planning, and to facilitate interagency communication and discussion about possible permitting issues before submission of the EP. At the IOP stage, operators may not have contracts for vessels finalized or precise dates of drilling, accordingly, specific names of contractors are not necessary, but could be provided. At the EP stage the operator must provide a general description of its SCCE capabilities and relief rig plans, in accordance with § 550.220(c), conforming to §§ 250.471 and 250.472. BOEM anticipates that the relief rig description may still be general at the EP stage, but will be detailed enough for BOEM to confirm that the operator has plans in place for how it will conduct operations safely in compliance with the regulations. Existing § 550.213(g) also requires that an EP include a blowout scenario addressing matters including surface intervention and relief well capabilities. Section 550.220(c)(1) requires the EP to provide a description of how an operator will design and conduct the proposed activities in a manner that accounts for Arctic OCS conditions; including a description of how the operator will manage and oversee those activities as an integrated endeavor. Additionally, § 550.220(a) requires that the operator submit a description of emergency plans describing the operator's ability to respond to a fire, explosion, personnel evacuation, or loss of well control, as well as a loss or disablement of a drilling unit, and loss of or damage to a support vessel, offshore vehicle, or aircraft with the EP. These new and existing provisions provide for the appropriate level of detail regarding an operator's plans at successive stages of the approval process. In response to the comment recommending that the IOP be included as an appendix to the EP application, BOEM will have received the operator's IOP at a minimum of 90 days before the EP submittal; therefore it is optional for the operator to include the IOP as an appendix in the EP. In response to the commenter's recommendation of having the public review and comment on the IOP, BOEM will post public versions of the operator's IOP to its Web site when received.

One commenter suggested requiring that drilling rigs not previously used in frontier areas, such as the Arctic OCS, undergo a mandatory third-party review of the unit's design and that such review be submitted as part of the EP application.

BOEM does not believe that the final regulations require amendment in response to this comment. The information provided with the operator's EP is general by necessity; more detailed information becomes available as the operator progresses through the planning process. In accordance with existing § 550.211(c), the EP must include a description of the drilling unit. Later in the planning process at the APD stage, under finalized § 250.470, BSEE requires the operator to submit specific information on the drilling unit. This includes information required in finalized paragraphs (a)(2) and (g) of § 250.470, such as detailed descriptions of how the drilling unit will be prepared for service on the Arctic OCS and how the operator will comply with the requirements of API RP 2N, *Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions,* Third Edition. The finalized requirements at § 250.473(a) mandate that all operators operating on the Arctic OCS use only equipment or materials that are rated or de-rated for service conditions that can be reasonably expected during operations.

Additionally, the operator's SEMS and the accompanying audit performed by a third-party must address the mechanical integrity of critical equipment. The revised requirements at § 250.1920(b)(5) will require Arctic OCS operators to increase their SEMS auditing frequency from every three years after the initial audit to every year in which drilling in the Arctic is conducted. Existing § 250.1920 requires that a third party Audit Service Provider accredited by a BSEE-approved accreditation body perform the audit. Accordingly, the proposed revisions are not necessary.

Two commenters recommend expanding the EP to address additional information including: Evidence that the operator consulted with marine mammal co-management organizations; a description of steps the operator will take to mitigate subsistence impacts, the establishment of appropriate start and stop timing for operations to minimize any potential conflict with subsistence activities, and an approved Conflict Avoidance Agreement (CAA) between the operator and the Alaska Eskimo Whaling Commission (AEWC). One of the commenters further recommended if a CAA is not included, then the EP should include an explanation as to the consultation process.

BOEM appreciates the commenter's concern for mitigating subsistence impacts and does not believe that the final regulations require amendment in response to this comment. For example, § 550.227 requires the operator to, among other things, assess the potential impacts of its proposed exploration activities, describe resources, conditions, and activities that could be affected by exploration operations (including impacts to marine mammals and subsistence and harvest practices), and list the agencies and persons that it consulted with regarding potential impacts associated with proposed exploration activities. Section 550.204(i) requires a description of the operator's efforts to minimize impacts on local community infrastructure. BOEM will also analyze subsistence impacts through its NEPA analyses.

With regard to the CAA processes, BOEM's Alaska OCS Region has regularly noted their positive value in public forums. The CAA is an agreement between AEWC and the operator and is considered a private agreement. As such, it is outside the scope of these regulations to require an operator to obtain a CAA from another entity. Although there is not a requirement for a CAA, discussion of resolutions during the consultation process and plans for continued consultation are required to be included in the EP. BOEM and BSEE continue to be committed to engaging on a routine basis with the AEWC. The AEWC leaders and members bring unmatched perspectives and insights into the relationships that BOEM and BSEE seek to maintain. With respect to the commenters suggestion that the operator be required to include evidence that the operator consulted with marine mammal co-management organizations, § 550.222 addresses the commenters

concerns. Section 550.222 requires the operator to include in its EP a description of the measures it took, or will take, to satisfy conditions of lease stipulations related to its proposed exploration activities. Because a lease stipulation can be formulated in collaboration with a co-management organization at the lease sale stage, evidence of how the operator satisfied the conditions of the lease sale stipulation must be included in the EP.

4. Additional Regulations by BSEE

What incidents must I report to BSEE and when must I report them? (§ 250.188)

The existing regulations at § 250.188 require operators to provide oral and written notification to the BSEE District Manager (who in the Alaska OCS region is the Regional Supervisor) of, among other things, any injuries, fatalities, losses of well control, fires and explosions, and incidents affecting operations. BSEE proposed to add a new paragraph (c) to this section requiring operators on the Arctic OCS to provide an immediate oral report to the BSEE onsite inspector, if one is present, or to the Regional Supervisor, of any sea ice movement or condition that has the potential to affect operations or trigger ice management activities, as well as to report the start and termination of these activities, and any ''kicks'' or operational issues that are unexpected and could result in the loss of well control. The new provision would likewise require a written report of ice management activities within 24 hours of their completion.

Several comments were received on this section. BSEE has evaluated these comments and decided to finalize § 250.188(c) as proposed. We have separated comments received on this section into two topics: (i) Comments on ice management reporting, and (ii) comments on reporting of kicks or operational issues that are unexpected and could result in the loss of well control.

Ice Management Reporting

Two commenters assert that the ice management reporting requirements are too subjective and vague, and that the reporting should be limited to ice incursion incidents that affect operations or trigger ice management activities as stated in the ice management plan. One of these commenters further asserted that the requirement would necessitate nearly constant communication with BSEE regarding sea ice movement and conditions, and requested that BSEE allow 24 hours to report the incident so the operator is able to focus on a safe response to the incident before contacting the regulator.

BSEE disagrees with these comments. The ice management reporting requirements of this provision require operators to remain in close communication with BSEE about sea ice conditions that have the potential to affect operations before they reach the point of triggering ice management activities as stated in the ice management plan. This requirement does not necessitate constant communication, as the reporting requirements are limited to sea ice movements or conditions that have the potential to affect operations or trigger ice management activities. Just as the operator needs to have sufficient time to plan and act in the event that ice poses an operational hazard, BSEE would need sufficient time to oversee the safety of an operator's reactions and prepare to respond, if a response is necessary, due to a safety or environmental incident resulting from an ice event. BSEE does not agree that the identified standard is vague or ambiguous, and is confident, including based upon recent experience in 2012 and 2015, that Arctic OCS operators will be able to implement the provision in practice, and in coordination with the BSEE inspector or Regional Supervisor.

The requirement to notify the BSEE inspector on location or the Regional Supervisor of sea ice movement or conditions that have the potential to affect an operation or trigger ice management activities is important and appropriate. BSEE agrees with the commenter's statement that the operator should focus on a safe response to an active incident, but we disagree with the commenter's request to allow 24 hours to report an incident. The requirement for an immediate oral report is satisfied by notifying the onsite inspector or BSEE Regional Supervisor when an event or potential event is recognized. Requiring an immediate oral report is reasonable and likely will not burden the operator. This requirement will ensure that BSEE is informed of ice management concerns but will allow the operator to focus on executing safe ice management operations. Consistent with the prioritization of safe ice management operations, the regulation allows 24 hours for the written report to be completed.

One commenter questioned the suitability of § 250.190, *Reporting requirements for incidents requiring written notification,* for use with the ice management reporting required by proposed § 250.188(c)(2), particularly in the case where there is no damage or injury. BSEE determined the information requested in § 250.190 is generally appropriate for these purposes, as all the information required may be relevant to reporting ice management activities in certain circumstances. The person completing the report has the option to state that specific information is not applicable (*e.g.,* no damage or injury occurred).

Two commenters suggested the ice monitoring requirement should be implemented to focus on the operators specifying reporting requirements in advance, based on the risks of a particular location, and these risks should be included in the ice management plan.

BSEE agrees in part. The operator is responsible for addressing the particular ice event, based on the ice management plan submitted to BOEM under § 550.220(c)(2). The operator's ice management plan should address how the operator will respond to and manage ice hazards, its ice alert procedures, and the procedures and thresholds for activating the ice management system. This ice management plan is required as part of the EP, which BOEM reviews to ensure the plan addresses all of BOEM's requirements. However, BSEE also believes that it is necessary and appropriate to establish baseline reporting requirements, not subject to individual operator plan specifications, to enable the agency to perform its necessary oversight functions, and therefore that no revision to the rule is needed in response to the comment.

One commenter proposes revising § 250.188(c)(1)(i) by deleting the requirement to report any sea ice movement or condition that has the potential to trigger ice management activities. The commenter suggests that compliance with these requirements would be achieved by including BSEE on the notification list used when an ice alert code is changed. BSEE does not agree that § 250.188(c)(1)(i) needs to be revised. The language of that provision makes it clear when the operator needs to notify BSEE. The commenter's suggested revision would change the mandatory reporting requirement to a provision allowing the operator to define its notification obligations through its ice management plan. Furthermore, it is the responsibility of the operator to determine how to comply with its notification obligations, including through use of its ice alert system.

Kick Reporting

Two commenters objected to the requirement to notify BSEE immediately

of a kick or an unexpected operational issue that could result in a loss of well control, as the operator should only focus on making conditions safe at the well site and this provision would take the operator's focus away from securing the well. One of the commenters recommended BSEE could be notified as soon as reasonably possible instead of immediately.

BSEE agrees with the commenter's statement that the operator should focus on a safe response to an active well control incident. The immediate reporting requirement is not intended to undermine safety, and safe operations always take precedence over satisfying reporting requirements. As discussed above in a similar comment to reporting any sea ice movement or condition that has the potential to affect operations or trigger ice management activities, the requirements finalized in this rulemaking allow 24 hours for the written report to be completed. It is appropriate to immediately provide an oral notification to the onsite inspector or Regional Supervisor as soon as an event or potential event is recognized. Accordingly, BSEE disagrees that this provision should be removed or revised. With the BSEE inspector on the rig during Alaska OCS exploratory drilling operations, an immediate oral report to that inspector is not only reasonable, but would not burden the operator. The provision also allows for notification to the Regional Supervisor if no inspector is onsite. Such notification is important to BSEE's fulfillment of its mandate to oversee operations to ensure safety and environmental protection.

One commenter asserted that the kick reporting requirement is more appropriate for inclusion in the Well Control final rule because there is no Arctic-specific reason to report kicks immediately.

BSEE evaluated this comment and determined it is appropriate to implement Arctic OCS specific requirements for kick reporting. As discussed in this preamble, the challenges to conducting operations and responding to emergencies in the extreme and variable environmental and weather conditions in the Arctic are demanding and distinct from those present in other OCS regions. Exploratory operations from MODUs on the Arctic OCS are conducted in sub-freezing temperatures, significant fog cover in the summer, strong winds and currents, storms that produce freezing spray and dangerous sea states, snow, and significant ice cover. Because of these conditions, the challenges of responding to kicks, and any resulting loss of well control, on the Arctic OCS are sufficiently distinct to justify distinct treatment. The Well Control Rule has national application and is therefore not the appropriate regulatory vehicle to address Arctic-specific concerns.

Three commenters request clarification that it is not BSEE's intent to direct well control activities beginning with any unexpected kick. The commenters assert that premature regulator intervention would increase confusion and any existing risks pertaining to the status of the well under such circumstances. Commenters also assert that including kick occurrence information with the daily and weekly well activity reports provides BSEE with the information it needs related to kick occurrence.

BSEE does not intend to direct well control activities and acknowledges that the operator is responsible for any immediate response to ensure the safety of the crew and facility. The notification requirements are within BSEE's authority to monitor and review any actions that may lead to a loss of well control. As described previously, safe operations are the primary concern. This requirement does not state, nor is there an implication, that the regulator will intervene in operations. However, proper response involves providing the regulator with timely and accurate information, so that it is actively aware of threats to well control. Merely including this information in well activity reports does not provide BSEE the information in a suitable timeframe.

One commenter requested that BSEE clarify what kicks are considered ''unexpected'' and could result in loss of well control. The commenter suggests that BSEE should provide reporting thresholds (*e.g.,* kick size) to assist operators in complying with this provision.

BSEE disagrees. The kick reporting requirement deliberately does not provide for the commenter's suggested reporting threshold. To the first part of the commenter's request, ''unexpected'' is intended to have its ordinary, typical definition, and an ''unexpected'' kick is one that is not anticipated in the course of normal operations and that could result in loss of well control. As with the ice management reporting requirements discussed above, BSEE determined not to prescriptively limit the reporting requirement to certain threshold triggers because it is essential for operators to remain in close communication with BSEE about any operational issues that are unexpected and could result in a loss of well control. Just as the operator needs to have sufficient time to act in the event of an incident that poses an operational hazard, BSEE would need sufficient time to oversee the safety of an operator's reactions and prepare to respond if a response is necessary due to a safety or environmental incident.

One commenter asked whether contractors or individuals are required to ascertain if the operator made the required reports, and to report independently if they have not.

As a general matter, BSEE looks to the designated operator to make filings and reports on behalf of all lessees and owners of operating rights. Because existing § 250.146(c) states that when a regulation requires that a lessee take an action, the person actually performing the activity is also responsible for complying with that requirement, it follows that the lessees' reporting duties could extend to a contractor to the extent that contractor actually performs the activity.

Documents Incorporated by Reference (§ 250.198)

The existing regulations at § 250.198 identify what documents BSEE has incorporated by reference. BSEE proposed to add paragraph (h)(95) to existing § 250.198 to incorporate by reference the API RP 2N, *Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions,* Third Edition. This document is a voluntary consensus standard addressing the unique Arctic OCS conditions that affect the planning, design, and construction of systems used in Arctic and sub-Arctic environments. This API document—which is virtually identical to a standard previously issued by the International Organization for Standardization (ISO), ''Petroleum and Natural Gas Industries Arctic Offshore Structures,'' First Edition (2010) (ISO 19906)—would be appropriate for certain aspects of drilling operations, such as accounting for the severe weather and thermal effects on structures, maintenance procedures, and safety. Since this final rule is focused on the exploratory drilling phase of operations on the Arctic OCS, certain portions of API RP 2N, Third edition (such as those related to issues regarding structural and pipeline integrity) would not be relevant. However, many elements of API RP 2N, Third edition could be effectively applied to equipment used in exploratory drilling operations on the Arctic OCS.

Several comments were received on this section. BSEE evaluated these comments and decided to finalize § 250.198 as proposed. Additional

comments specific to the requirement to comply with applicable provisions of API RP 2N Third edition, are discussed in responses to comments on paragraph (g) of § 250.470, *What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?*.

Several commenters oppose incorporating API RP 2N Third edition because, at the time of publication of the NPRM, API RP 2N Third edition was in draft form. Therefore, they assert that the final version should not be incorporated in the final rule. One of the commenters requested an additional 30-day public review and comment period for the final API RP 2N Third edition. Additionally, several commenters suggested that ISO 19906 should be incorporated by reference.

BSEE disagrees. Since the effect of incorporating a document by reference is no different than printing the requirement directly in the **Federal Register** (*see* 5 U.S.C. 552(a)(1), the same principles that normally apply to the relationship between proposed and final rules would apply to the relationship between proposals to incorporate a document by reference and the final incorporation by reference of a document. Accordingly, the **Federal Register** contemplated that an agency may propose one standard for incorporation and finalize a rule with a different standard based on changed circumstances or public comments (79 FR 66267, 66268 (November 7, 2014)).

The relevant question is whether the NPRM's discussion of draft API RP 2N Third Edition gave adequate notice of the requirements that the Department is now finalizing. The test for adequate notice is whether the final rule is a logical outgrowth of the proposed rule.[18] Incorporation of the final version of API RP 2N Third Edition is a logical outgrowth of the proposal to incorporate the draft version of the same standard. The final version of API RP 2N Third Edition is largely identical to the version referenced at the time of the proposed rule. The principal change from the draft to the final was the removal of two paragraphs from Section 7.2.2.4 of the final version of API RP 2N Third Edition. This deletion does not meaningfully alter the substance of API RP 2N Third Edition in a manner not logically related to or reasonably foreseeable from the proposed incorporation. The final version allows that that the relevant probability levels associated with abnormal-level ice events are not specifically mandatory as was proposed, but are instead recommended. The effect of this change should be small since, whether the language in the standard is mandatory or hortatory, the regulation—like the proposed rule—requires operators to describe in their APD how they will utilize the best practices of API RP 2N Third Edition. Moreover, the preamble discussed the possibility of finalizing a rule incorporating ISO 19906, which was characterized in the preamble as ''virtually identical'' to the draft version of API RP 2N Third Edition (80 FR 9916, 9938 (Feb. 24, 2015)). This discussion put the public on notice that the document incorporated in the final rule may not be actually identical to the draft version of API RP 2N Third Edition. The final version of API RP 2N Third Edition incorporated into this rule remains largely identical to the ISO 19906 standard recommended for incorporation by the commenter.

One commenter asserted that BSEE should not incorporate ISO 19906 through the rulemaking because it does not apply specifically to MODUs.

BSEE disagrees. Although we are incorporating by reference the applicable provisions of API RP 2N Third Edition, rather than ISO 19906, the rationale is identical. While the commenter is correct that ISO 19906 (or API RP 2N Third Edition) does not apply specifically to MODUs, the procedures relating to ice actions and ice management contained in the standards can be applied to such units. The rule does not purport to incorporate and apply to MODUs every aspect of these standards, but rather requires the operator to describe how it will utilize the relevant best practices and specifically identifies portions that are not applicable.

Two commenters oppose the incorporation by reference of API RP 2N Third Edition because its incorporation by reference into BSEE regulations conflicts with API's intent that RPs should not be applied inflexibly and should not replace sound engineering judgment. BSEE disagrees that there is a conflict between the finalized incorporation by reference provisions of this rule and the intent of RPs. As stated in finalized § 250.470(g), an operator must comply with the incorporated provisions of API RP 2N Third Edition where it does not conflict with other Arctic OCS requirements under 30 CFR part 250, and must provide a detailed description of how the operator will utilize the best practices included in API RP 2N Third Edition. Accordingly, the flexibility of the application of RP 2N Third Edition is retained while providing for regulatory oversight of how the provisions will be tailored to each APD.

Two commenters suggest lease operators and drilling contractors utilize applicable class rules from classification societies recognized by the International Association of Classification Societies (IACS) to determine what, if any, measures need to be taken from a vessel structure and equipment perspective based upon the area of operations and the seasonal conditions that are expected to be encountered. Another commenter also opposed the incorporation of API RP 2N Third Edition, or ISO equivalents, as an absolute requirement due to the variability of operations that may be conducted in the Arctic and the potential restrictions that could result from such a prescriptive requirement. The commenter recommended the rules focus on operators proving critical equipment fit for Arctic use based on the specific operating environment and assumptions for the given project.

BSEE disagrees. We recognize that MODUs are designed for a specific set of criteria or are classed for a specific environment, water depth, and drilling capacity which, in combination, establishes the design limits of the MODU. Because MODUs are not traditionally designed and/or classed specifically for the environmental conditions found in the Arctic region, it is necessary, if MODUs are to be considered for exploratory drilling on the Arctic OCS, to have in place criteria for the assessment of the site and the MODU for these uniquely challenging operating conditions. API RP 2N Third Edition is the current industry standard that, although not specifically applicable to MODUs, provides the criteria for site and MODU assessment because the procedures relating to ice actions and ice management contained in the standards can be applied to such units. Even if the MODU is reclassified or redesigned for Arctic conditions, operators will still need to perform an assessment for the specific environmental conditions during the planned window of operations of the MODU on the Arctic OCS in compliance with the final APD requirements of § 250.470. Equipment on the MODU used to support the drilling operations should also be evaluated for suitability for Arctic conditions, but should be evaluated using the appropriate standards for equipment operating in the Arctic environment, not a structural design standard for the Arctic region. BSEE's existing regulation at § 250.418(f) requires that operators include in their APD evidence that, in areas subject to subfreezing conditions

[18] *See Long Island Care at Home, Ltd.,* v. *Coke,* 551 U.S. 158 (2007).

''the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions'', while final § 250.473(a) establishes a requirement for use of appropriately rated or de-rated equipment and materials. Operators may ensure that proposed materials and equipment are rated or de-rated appropriately by referencing manufacturer specifications and would not need to obtain equipment or material rating by an independent third-party rating entity.

Two commenters recommended other international standards, such as the International Maritime Organization (IMO) Standard for Ships Operating in Polar Waters, 2010 Edition and the Arctic Council Arctic Offshore Oil and Gas Guidelines, should be considered for incorporation by reference.

For this final rule, BSEE has determined that the incorporation by reference of the applicable provisions of API RP 2N Third Edition codifies appropriate standards to regulate MODUs and jack-up rigs conducting exploratory drilling operations on the Arctic OCS. BSEE will continue to review other standards to determine their applicability and the propriety of incorporating them, in addition to API RP 2N Third Edition, to support Arctic OCS exploration using MODUs.

One commenter does not support the incorporation of ISO 19905–1 in the final rule. Another commenter noted BSEE should be aware of the limited applicability of ISO 19905–1 to the assessment of self-elevating units, while ISO 19906 is intended to be used irrespective of structure type. The commenter points out that ISO 19905–1 relies on ISO 19906 for the determination of ice actions which, in practice, means that ISO 19906 has to be used as well.

BSEE agrees with the commenter and determined to incorporate by reference API RP 2N Third Edition. BSEE also agrees with the comment regarding the relationship between ISO 19905–1 and ISO 19906. BSEE recognizes that MODUs are designed for a specific set of criteria or are classed for a specific environment, water depth, and drilling capacity which, in combination, establishes the design limits of the MODU. API RP 2N Third Edition is the current industry standard that provides the criteria for site and MODU assessment. If industry develops additional standards or guidelines for the assessment of MODUs in the Arctic region, then BSEE may consider those during future rulemakings.

Two commenters recommended that any standards incorporated by reference should be available online to the public free of charge. One of the commenters asserted that because the documents were not freely available during the public comment period, neither API RP 2N Third Edition nor ISO 19906 qualify as being ''reasonably available'' as discussed in the **Federal Register**'s final rule, *Incorporation by Reference* (79 FR 66267, November 7, 2014).

BSEE disagrees with the assertions of these commenters. The **Federal Register** requires that, for a proposed rule, the preamble must: (1) Discuss the ways that the materials it proposes to incorporate by reference are reasonably available to interested parties or how it worked to make those materials reasonably available to interested parties; and (2) Summarize the material it proposes to incorporate by reference. (1 CFR 51.5(a)). The proposed rule preamble met both requirements.

First, it included a discussion of how interested parties could view a copy of the draft version of API RP 2N Third Edition, and it stated that once the standard was finalized by API it would continue to be available on API's Web site for free viewing or for purchase in electronic or hard copy. Specifically, the NPRM preamble stated: ''BSEE proposes to incorporate, with certain exclusions discussed later in this proposed rule, draft proposed API RP 2N, Third Edition, which is available for free public viewing during the API balloting process on API's Web site at: *http://mycommittees.api.org/standards/ecs/sc2/default.aspx* (click on the title of the document to open). When finalized by API, that standard will be available for free public viewing on API's Web site at: *http://publications.api.org*'', (80 FR 9916, 9933 (Feb. 24, 2015)). (A footnote to this text explained that, to find the document on API's Web site, a user had to first create an account and accept the terms and conditions before it could browse through documents.) The commenters are incorrect to assert that the document was not available for free online either during the comment period for this rulemaking or after finalization of this rule or the API standard. Additionally, as is stated in the preamble of the proposed rule, the documents may be inspected, upon request, at the BSEE office in Sterling, Virginia (45600 Woodland Road, Sterling, VA 20166 (phone: 703–787–1587) or at the National Archives and Records Administration (NARA). For information on the availability of materials at NARA, call 202–741–6030, or go to: *www.archives.gov/federal-register/cfr/ibr-locations.html.*

Further, BSEE is permitted to incorporate by reference (IBR) copyrighted materials into its regulations, and the OFR has expressly concluded that an agency's IBR of copyrighted material does not result in the loss of that copyright.[19] Implicit within that is the fact that access to certain incorporated standards is controlled principally by the third party copyright holder. While BSEE works diligently to maximize the accessibility of incorporated documents, and offers direction to where the materials are reasonably available, it also must ultimately respect the publisher's copyright. Accordingly, most issues related to how API administers access to its copyrighted materials—including its decision to charge for them—are outside of BSEE's control.

The **Federal Register**'s regulations state that, if a proposed rule does not meet the applicable IBR requirements, the Federal Register Director would return the proposed rule to the agency, 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) (discussing the reasons that the **Federal Register** specifically declined to include such requirements in its regulations on IBR).

Second, the preamble to the proposed rule also included a summary of the RP 2N Third Edition. Early on the preamble stated that the document ''would be appropriate for certain aspects of drilling operations, such as accounting for the severe weather and thermal effects on structures, maintenance procedures, and safety.'' (80 FR 9932). Later, describing which parts of RP 2N would not apply, the preamble indicates different kinds of structures that are covered under RP 2N and are subject to BSEE's jurisdiction. *Id.* at 9938 (''For example, Class requirements do not cover the derrick, plumbing, pipes, tubing, and pumps that are all also structural components of a MODU and that fall under BSEE jurisdiction.'').

Two commenters recommend the regulations include a complete and clearly organized summary of the API RP 2N Third Edition provisions being incorporated. One of the commenters asserted that the rule should include a technical evaluation explaining the criteria used to determine whether a

[19] *See* 79 FR 66273 (Nov. 7, 2014) (''recent developments in Federal law . . . have not eliminated the availability of copyright protection for privately developed codes and standards referenced in or incorporated into federal regulations''); *see also Veeck* v. *Southern Building Code Congress Int'l, Inc.,* 293 F.3d 791 (5th Cir. 2002).

provision is incorporated by reference, and that before incorporating a document by reference into the regulations, BSEE should be required to show that it has reviewed the document and has determined that it meets the best available and safest technology and operating practices standard.

BSEE disagrees. The preamble to the NPRM included a summary of API RP 2N Third Edition. The NPRM preamble stated that the document ''would be appropriate for certain aspects of drilling operations, such as accounting for the severe weather and thermal effects on structures, maintenance procedures, and safety'' (80 FR at 9932). It also described which parts of RP 2N Third Edition would not apply, and the preamble indicated which kinds of structures are covered under RP 2N Third Edition and subject to BSEE's jurisdiction. *Id.* at 9938 (''For example, Class requirements do not cover the derrick, plumbing, pipes, tubing, and pumps that are all also structural components of a MODU and that fall under BSEE jurisdiction.''). BSEE thoroughly evaluated API RP 2N Third Edition and described in § 250.470(g) the manner in which it was being incorporated into the rules, including which aspects of the RP were expressly excluded from incorporation. BSEE disagrees that the other thresholds suggested by the commenter are necessary or appropriate prerequisites for incorporation of a standard by reference.

Pollution Prevention (§ 250.300)

BSEE proposed to revise § 250.300 pollution prevention regulations to address Arctic OCS exploratory drilling operations by adding provisions in paragraphs (b)(1) and (2). These provisions would require that, during exploratory drilling operations on the Arctic OCS, the operator must capture all petroleum-based mud, and associated cuttings from operations that use petroleum-based mud, to prevent their discharge into the marine environment. The provisions also state that the Regional Supervisor may require capture of all water-based mud, and associated cuttings, from operations after completion of the hole for the conductor casing to prevent its discharge into the marine environment based on certain conditions such as: Proximity of drilling operations to subsistence hunting and fishing locations; the extent to which discharged mud or cuttings may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or the extent to which discharged mud or cuttings may adversely affect marine mammals, fish, or their habitat.

Several comments were received on this section. BSEE has reviewed the comments and determined, with the exception of various technical edits, the substantive provisions of § 250.188 are finalized as proposed.

Many commenters assert that the pollution prevention requirements set forth in the revisions to § 250.300 are unnecessary and redundant with existing authorities or exceed BOEM and BSEE's jurisdiction. Several commenters further assert that the provisions specifically duplicate or conflict with EPA regulations under the CWA, as implemented through National Pollution Discharge Elimination System (NPDES) general permits and strict monitoring requirements. One commenter suggests that BOEM and BSEE should defer to the National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS) and its Incidental Harassment Authorization program with respect to potential impacts on marine mammals and subsistence hunting activities.

BSEE disagrees with the commenters. BSEE has the authority to implement the proposed changes to § 250.300, and furthermore the pollution prevention provisions of this final rule do not conflict with the authority of other agencies, such as the EPA and NOAA, to regulate discharges into the marine environment from oil and gas operations on the OCS.

Under OCSLA, BOEM and BSEE are jointly responsible for implementing environmental safeguards to ensure that oil and gas exploration and production activities on the OCS are conducted in a manner which minimizes damage to the environment and dangers to life or health, which provides for the conservation of the natural resources of the OCS, and which will not be unduly harmful to aquatic life in the area, result in pollution, create hazardous or unsafe conditions, or unreasonably interfere with other users of the area.[20] BSEE is fulfilling this obligation by preventing petroleum-based drilling mud and associated cuttings from entering the Arctic environment and by clarifying BSEE's authority to limit the release of water-based mud and associated cuttings in appropriate contexts, such as when operations are near areas where marine mammals may be concentrated or near important subsistence hunting and fishing locations. The changes to § 250.300 are fully within our authority under OCSLA.

E.O. 12777 delegated the functions vested in the President by section 311(j)(1)(C) of the CWA to the Secretary, among others. These delegations establish a cooperative and complementary system for implementing the requirements of the CWA among the Secretary, EPA, NOAA, and others. The functions delegated to the Secretary authorize the Secretary to establish procedures, methods and equipment and other requirements for equipment to prevent and contain discharges of oil and hazardous substances from offshore facilities. The revised language of § 250.300 is consistent with this authorization and does not conflict with any other delegation of authority. By requiring the capture of mud and cuttings associated with exploratory drilling operations on the Arctic OCS under the identified conditions, BSEE is establishing procedures, methods, equipment and requirements for equipment to prevent or contain the discharge of oil and hazardous substances from offshore facilities, as is contemplated by section 311(j)(1)(C) of the CWA. Thus, the changes to § 250.300 are fully within BSEE's authority under the CWA.

The revisions do not conflict with the NPDES general permits issued by the EPA in November 2012. The NPDES permits authorize certain discharges from oil and gas exploratory facilities on the OCS in the Beaufort Sea and the Chukchi Sea, including certain discharges of water-based drilling fluids and drill cuttings, subject to effluent limitations and other requirements. The permits do not allow the discharge of oil-based drilling fluids in any location or at any time or the discharge of water-based drilling fluids and drill cuttings during the fall bowhead whale hunt in the Beaufort Sea. The revisions to § 250.300 are designed to complement, and do not conflict with, these permits. Further, as an agency statutorily responsible for minimizing environmental damage from oil and gas exploration activities on the OCS, BSEE has the authority to issue regulations that are more stringent than the NPDES permits issued by EPA. Nothing about the EPA's authority to regulate pursuant to the CWA detracts from the Secretary's delegated OPA authority under E.O. 12777 or direct authority under OCSLA.

Finally, when writing the rule, BSEE consulted with the EPA, NOAA, and other Federal agencies about regulating discharges from operations on the OCS. In addition, once this rule is final, BSEE will continue its practice of

[20] *See, e.g.,* 43 U.S.C. 1332(3), 1332(6), 1334(a), 1340(g), 1348(b).

communicating with other agencies responsible for oversight of discharges related to oil and gas exploration drilling in the Arctic. This communication will help ensure that conflicts do not arise.

Several commenters were generally supportive of the pollution prevention requirements, but request that the requirements mandate the capture of all water-based mud and cuttings. One of these commenters also asserted the operator should have the burden of demonstrating lack of harm associated with waste discharges, noting subsistence hunting concerns, because marine mammals traverse through areas where the regulated pollution may be discharged.

BOEM and BSEE do not agree that all water-based mud and cuttings must be captured. This final rule implements the statutory mandate under OCSLA to promote oil and gas development while protecting the environment. The Bureaus have not seen sufficient evidence to suggest that water-based mud and associated cuttings are sufficiently problematic in all circumstances to justify a uniform capture requirement. Regarding the comment recommending the operator bear the burden of demonstrating a lack of harm to subsistence hunting, we determined that the final rule addresses the commenter's concern. For example, the requirements in § 250.300(b)(1) and (2) clarify BSEE's authority to prevent discharges based on potential effects to subsistence hunting activities and environmental concerns related to the marine environment. In addition to OCSLA, BOEM must comply with mandates of other Federal laws (*e.g.,* ESA). Further, DOI initiates Government-to-Government Consultations with federally recognized Tribes and Government-to-ANCSA-Corporation Consultation pursuant to Secretarial policy and direction.

Additionally, during the EP review process BOEM conducts environmental review of the EP, which includes addressing subsistence-harvest patterns, socio-cultural systems, and environmental justice. BOEM's environmental review describes the direct, indirect, and cumulative effects on the offshore and onshore environments expected to occur as a result of exploration activities. BOEM's Environmental Assessments (EA) describe the direct, indirect, and cumulative effects on the offshore and onshore environments expected to occur as a result of implementation of EPs. The analytical conclusions must clearly identify whether potential effects are significant, including through relevant information regarding environmental consequences obtained through consultation and review by interested parties. The EA must also identify the agencies and persons consulted with regard to potential effects associated with activities within an EP. Controversial issues and substantive opposing or conflicting views raised by Federal, State, or local agencies, Tribes, or the public regarding the level of environmental impact of the proposal will be addressed. Relevant approvals are also conditioned on compliance with protective restrictions and mitigations put in place by the U.S. Fish and Wildlife Service (USFWS) and NMFS. Through these and other measures, the Bureaus are able to sufficiently analyze and mitigate impacts to marine mammals and subsistence activities, and no revision to this provision is necessary.

One commenter suggests that any determination to allow the discharge of water-based drilling cuttings be made at the permitting stage to allow the operator adequate time for planning and installation of equipment and resources.

BOEM and BSEE agree that pollution prevention requirements should be considered as early as possible. Any determination by the BSEE Regional Supervisor that the operator must capture all water-based mud from operations after completion of the hole for the conductor casing will be made as soon as feasible, on a case-by-case basis, to allow for consideration of newly discovered impacts and impacts that may result from permit modifications. NEPA analysis of proposed exploration activities will help inform BSEE's determination.

Two commenters support the requirements to capture all petroleum-based muds and associated cuttings. One commenter recommended the provisions contain a narrowly defined exception for technical infeasibility, with the burden of proof placed on the operator to demonstrate technical infeasibility in its EP.

We disagree with the commenter's suggestion to allow an exception for technical infeasibility. We believe it is technically feasible, and a common industry practice today, to collect the petroleum based mud and cuttings and back haul them for disposal at an approved onshore disposal site. Existing regulations already provide for departures and use of alternate procedures under appropriate circumstances.

Several commenters recommend the capture requirement be extended to all discharges. One of the commenters further recommended the prohibition of all discharges when technically feasible, with the burden of proof on the operator, and asserted that there would only be an incremental increase in costs offset by cost savings from avoided discharge monitoring, record keeping, reporting, and sampling for heavy metal contamination in marine sediment.

Under existing § 250.300(b)(1), BSEE already has the authority to restrict the rate of drilling fluid discharges or prescribe alternative methods if environmental or operational concerns are raised. Amendments to the section clarify the Regional Supervisor's authority to impose operational measures that complement EPA's discharge limitations by considering potential impacts to specific components of the Arctic environment, such as subsistence activities, marine resources, and coastal areas.

The EPA has the authority to issue NPDES general permits for discharges under CWA section 301(a), 33 U.S.C. 1311(a), which generally prohibits the discharge of pollutants to the waters of the U.S. unless authorized by a NPDES permit. EPA typically issues NPDES general permits, rather than individual permits, for discharges from offshore oil and gas exploration facilities. The EPA uses the results of Ocean Discharge Criteria Evaluations (ODCE) and traditional knowledge when issuing general permits for oil and gas activities. For example, one of the criteria analyzed by EPA for ODCE is the potential impacts of discharges on human health through direct and indirect pathways. As subsistence hunting is directly related to human health, the EPA can require mitigation practices, such as environmental monitoring programs or restrictions on discharges during subsistence hunting seasons. The EPA addressed subsistence hunting concerns in its October 2012 Environmental Justice Analysis for Support of NPDES General Permits for Oil and Gas Exploration facilities in the Beaufort and Chukchi Seas.

We note the requirements finalized at § 250.300(b)(2) require the capture of all cuttings from Arctic OCS operations that utilize petroleum-based mud and, after consideration of various factors, the Regional Supervisor also has discretion to require the capture of cuttings from operations that utilize water-based mud. Additionally, under existing § 550.202, BOEM ensures, among other things, that the operator conforms to sound conservation practices, does not interfere with other uses of the OCS, and does not cause harm to the human, marine, or coastal environment. Both existing regulations and the requirements finalized at

§ 250.300 provide for both mandatory limitations of discharges of petroleum-based substances and regulatory discretion to prohibit drilling discharges that may be harmful to the marine environment. These requirements complement EPA permitting and regulation of discharges related to OCS operations.

One commenter disagrees with providing the Regional Supervisor discretion to prohibit both water- and petroleum-based mud and cuttings based on environmental factors, including migratory patterns and adverse effects to marine mammals, fish or their habitat. The commenter asserted that there is no scientific evidence suggesting whales detect odors from drilling, let alone respond to odors in a way that would substantially alter their migration patterns. Accordingly, the commenter asserted, concomitant changes to subsistence hunting, such as hypothetically needing to travel farther beyond historic whale migration routes and hunting areas, are not expected.

BSEE has existing authority under § 250.300(b)(1) to restrict drilling fluid discharges or prescribe alternative methods if environmental or operational concerns are raised. Amendments to the section clarify and provide guidance regarding the Regional Supervisor's authority to impose operational measures that complement EPA's discharge limitations by considering potential impacts to specific components of the Arctic environment, such as important subsistence activities, marine resources, and coastal areas. In crafting these amendments, the Bureaus considered all available science-based factors and traditional knowledge and determined the environmental effects of discharges into waters surrounding operations should be one of the factors the Regional Supervisor may consider when prohibiting discharges of water-based muds and associated cuttings. BOEM incorporates both science and traditional knowledge in its environmental documents prepared under the NEPA. This NEPA analysis helps ensure that BOEM and BSEE make decisions based on an understanding of environmental consequences with the intent to protect, restore, and enhance the environment of the Arctic OCS while balancing the Nation's need for oil and gas resources.

One commenter recommended rewording the provisions to allow for a science-based assessment to be reviewed by BSEE and stakeholders as part of a transparent process.

As a standard practice, BOEM and BSEE consult with Federal, State, and local governments, as well as federally recognized Alaska Native Tribes and ANCSA Corporations, and provide opportunities to be informed by the scientific community, non-governmental organizations, and concerned citizens to maintain transparency. However, for activity authorized under OCSLA, final decisions will rest either with BOEM under part 550 authorities or with BSEE under part 250 authorities. These decisions are made to protect the best interests of the Nation and in compliance with other Federal law, including, for example, NEPA, ESA, or the Marine Mammal Protection Act (MMPA).

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

BSEE proposed to add a new paragraph (c) to the former § 250.402. As discussed in Section IV.A, the contents of § 250.402 were subsequently moved to a new § 250.720 by the Well Control Rule. Therefore the new paragraph (c) has been finalized at § 250.720(c) in this rulemaking. This new paragraph requires exploratory drilling operators on the Arctic OCS to ensure that any equipment left on, near, or in a temporarily abandoned well that has penetrated below the surface casing be secured in a way that would protect the well head and prevent or minimize the likelihood of the integrity of the well or plugs being compromised. The primary concern this provision is designed to address is the possibility that ice floes could sever, dislodge, or drag any exploration-related equipment, obstructions or protrusions left on the well or the adjacent seafloor. The language, however, is drafted to encompass damage from any foreseeable source. The provision in paragraph (c)(1), which is designed to be performance-based, would allow operators to devise optimal strategies for identifying and accounting for threats to the integrity of equipment left on the OCS, and would be limited only to exploration wells that have penetrated below the surface casing.

However, for exploration wells located in an area subject to ice scour, based on a shallow hazards survey, final paragraph (c)(2) would require a mudline cellar or equivalent means of minimizing the risk of damage to the well head and well bore. BSEE added ''well bore'' to the provision to clarify that ice scour presents risks to equipment located both at the well head and in the well bore. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection required if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks. The BSEE Regional Supervisor will evaluate, during the APD process, whether a proposed equivalent approach is sufficiently protective.

Several commenters supported a performance-based approach and recommended that the final rule revise proposed § 250.402(c) to permit an operator to select technology that can best address the source control event according to the operator's plan. One of the commenters argued that a prescriptive approach to regulation stifles innovation, introduces uncertainty and promotes a particular type of spill response technology still in development, at the expense of other approaches combining different components that may provide equal or better protection against risk. This commenter asserted that the rulemaking does not provide a basis for determining how equivalency should or could be demonstrated by an operator or how it would be evaluated by the regulators.

BSEE agrees with the importance of allowing for the use of technology that is best suited to an operator's plan and understands that technology may exist or be developed that provides equal or better protection against risk than that prescribed in the regulation. To clarify this, we are revising the language in proposed § 250.402(c)(2). The finalized regulation at § 250.720(c)(2) establishes a performance standard, while also specifying a prescriptive method for achieving the performance standard. Section 250.720(c)(1) provides that an operator must ensure applicable equipment is ''positioned in a manner'' that will protect the well head and prevent or minimize the likelihood of compromising the downhole integrity of the well or the effectiveness of the well plugs, but does not dictate how those ends are to be achieved. Additionally, in areas of ice scour, § 250.720(c)(2) specifically allows for ''an equivalent'' to a well mudline cellar as an alternative means to protect the well head and wellbore. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection required if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks. The flexibility provided by these performance-based standards is adequate to address the commenter's concerns.

Existing regulations also facilitate the approval of alternate equipment and procedures. Section 250.141—*May I ever use alternate procedures or equipment?* –allows for the District Manager or Regional Supervisor to approve the use of alternate procedures or equipment provided the operator can show the compliance measures will meet or exceed the level of safety and environmental protection required by this provision.

Regarding the commenters' concern that this rulemaking does not provide a basis for determining how equivalency should or could be demonstrated by an operator or how it would be evaluated by the regulators, we note the concern and have added a discussion in Section III.B to clarify how BSEE implements the provisions of § 250.141. Under § 250.141(c), the operator must submit information or give an oral presentation to the Regional Supervisor describing the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

One commenter suggested that the final regulations should allow for the use of an open system, such as the use of a rotating head, managed pressure drilling, and/or riser gas handler, as this would allow for closer monitoring of flows and wellbore pressures. The commenter asserted that use of these options would protect against the formation of undetected or unconfirmed hydrocarbons arriving at an open surface arrangement with no backpressure and subsequent violent expansion/release of hydrocarbon gas clouds. The commenter recommended that the system used be determined based on water depth and other well/drilling rig parameters.

BSEE generally agrees, with the qualification that use of a system that incorporates a rotating head device, managed pressure drilling (MPD) technology, and/or riser gas handlers, is only appropriate in certain situations. For example, in settings such as the Gulf of Mexico, particularly in deep water where the safe drilling margin is typically very narrow, this technology has been used effectively. Currently, we are aware of four different MPD type systems available for use in the Gulf of Mexico, including use of a rotating control device. These include the following: (1) Constant bottom hole pressure for drilling in narrow or relatively unknown safe mud weight windows; (2) return flow control for early kick-loss detection; (3) mud cap drilling for drilling in severe to total loss zones with sacrificial fluids; and (4) dual gradient drilling for drilling in water depths greater than 5,000 feet. Use of open systems may have applicability in frontier areas such as the Arctic OCS where additional hydrostatic control may be advantageous to ensure a well is drilled safely. The provisions finalized at § 250.720(c) do not preclude an operator from proposing use of such a system in areas of ice scour. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection provided by a mudline cellar if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks. Additionally, an open system may be approved as an alternate procedure or equipment under § 250.141 if it is demonstrated to provide an equivalent means of minimizing risk of damage to the well head and wellbore.

One commenter recommended that BSEE provide guidance regarding the use of a slim-hole ''closed'' system approach during an initial exploration phase. The commenter asserted that a slim-hole approach may be quite possible in the Arctic and would result in far less impact on the environment for exploration drilling where no incident occurred. Additionally, the commenter asserted that the ''closed'' system allows for far better monitoring of flows in and out of the well.

BSEE agrees with the comment, as the use of a slim hole ''closed'' system approach to exploratory drilling operations on the Arctic OCS may have benefits in certain situations. As stated above, the provisions of this section do not preclude an operator from proposing use of such a system, if it can be demonstrated to provide an equivalent means of minimizing risk of damage to the well head. The existing regulations at § 250.141 also allow an operator to propose alternative methods of compliance if they can validate that such proposals provide for an equivalent or greater level of safety to personnel and the environment as what is required in the regulations.

One commenter suggested the use of a comprehensive up-to-date barrier diagram for each well, showing the condition and verification of each component of the barrier system. The commenter suggests that this diagram should be available for all involved to see and for inspection by authorities without notice.

BSEE agrees with having a barrier diagram for each well and has determined the concern is addressed in existing regulations. Section 250.413, *What must my description of well drilling design criteria address?,* requires the operator to submit a well diagram/wellbore schematic that includes the various barriers in a well (*e.g.,* casing, liners, cement, downhole seal assemblies, plugs, drilling fluids, etc.) as part of the information submitted in a typical APD. Barrier information (*e.g.,* packers, tubing, completion fluids, subsurface safety valves) is also required as part of a well completion application in the form of a wellbore schematic. If completion is planned and this data is available at the time the operator submits the APD and Supplemental APD Information Sheets (Forms BSEE–0123 and BSEE–0124), the operator may request approval on those forms. BSEE believes these two schematics adequately address well barriers and that no revisions to the rule are necessary.

One commenter recommended there should be improvements, as appropriate, to the barrier system, specifying that these may include improvements to BOP equipment and to the monitoring and verification of casing/tubular connections.

We agree with the importance of improvements to barrier systems used during the drilling of a well. In addition to improvements enacted through this rulemaking, BSEE finalized several additional improvements to barrier systems in the Well Control Rule. BSEE also participates in various standards development work groups and workshops and has assisted with the preparation of Systems Reliability Technical Evaluations.[21] BSEE has also initiated and funded approximately 30 research projects to assist in implementing various improvements to key barrier systems. Studies of interest being conducted through the agency's Technical Assessment Program (TAP) include TAP #737—Risk Assessment for Life Cycle Management and Failure Reporting Systems and TAP #753—Evaluation of the Collection and Application of Risk Data. Other TAP studies on barriers address BOP system reliability, BOP shearing technology, safety management systems and subsurface safety valves.[22] BSEE has also entered into an Interagency Agreement with Argonne National Laboratories to evaluate risk and further study drilling barrier management, including projects on BOP control

[21] *E.g.,* QC–FIT Evaluation of Seal Assembly & Cement Failures Report #2014–02, December 2014, QC–FIT Evaluation of Connector and Bolt Failures Report #2014–01, August 2014.

[22] TAP studies are available at *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Categories/Production.*

systems, shear ram certifications, risk-based inspection and regulatory practices, and risk-based decision making. Accordingly, while BSEE agrees with the importance of continuously pursuing improvements to barrier systems, it does not believe that any revisions to this rule for that purpose are necessary or appropriate at this time.

One commenter cautioned that operations should recognize limits of the casing shoe and potential consequences, should the leak off test pressure be exceeded. The commenter recommended the regulations require an estimate of the shoe strength, updated as information becomes available, and an assessment of what pressures will be imposed upon the shoe (as the weakest point in the openhole section of the wellbore) given the well/formation characteristics, uncertainties and potential interacting operations. The commenter highlights the Frade incident (Chevron, Brazil, 2010) as an example of what can happen when these issues are not adequately addressed.

BSEE is aware of the significance of the Frade incident, during which an estimated 4,600 barrels of oil leaked into the ocean during the drilling of an appraisal well in the Frade Offshore Field off the coast of Brazil, and has held various discussions with Brazil's National Agency of Petroleum, Natural Gas and Biofuels since the incident to better understand its causes. The agency believes that existing regulations at § 250.427, which require a pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe, are adequate to prevent such an incident happening on the Arctic OCS, even though these provisions do not require an additional pressure integrity test to update a shoe's strength.

One commenter recommended revising the proposed rule to allow for better flow measurement in and out of the well. The commenter also suggested the need for better understanding of what differences could occur between flow in and flow out, specifying that this is needed where there is hydrocarbon within the flow system. The commenter asserted that it is essential to undertake detailed modeling of potential events in order to recognize potential issues and mitigations to be taken, and ensure that crews are properly and effectively trained.

BSEE agrees with the comment on addressing better measurement of flow in and flow out of a well as a way to improve safety. In December 2015, the agency completed a TAP study, #743-Evaluation of Automated Well Safety, studying early kick detection and managed pressure drilling, including use of a Coriolis meter to monitor flow in/flow out of a wellbore. This study identifies automated well safety technologies with the potential to increase safety during OCS drilling, well completion, well work over and production operations, as well as to assess early well kick detection approaches, equipment, techniques, and systems associated with drilling operations on the OCS. These studies will help us to identify and address improvements in flow measurements.

One commenter recommended that, if a marine riser is used, additional instrumentation should be included to identify and provide alarms to address the presence of previously undetected hydrocarbons in the riser prior to these hydrocarbons reaching the surface.

BSEE agrees with the commenter on the importance of detecting hydrocarbons in a drilling riser and notes that our existing regulations—formerly at § 250.446(b) and moved by the Well Control Rule to new § 250.739(c)—require a visual inspection of the riser at least every three days, weather and sea states permitting. BSEE believes that this requirement is adequate to assure the integrity of this system without installing additional riser instrumentation. Using additional riser instrumentation would not be an effective means of detecting hydrocarbons in drilling risers in the Arctic because of the short riser length needed to conduct shallow water drilling operations like those typically conducted on the Arctic OCS. In the event of a kick, short riser lengths will provide a limited amount of time between when a kick is detected in the wellbore and when the kick reaches the surface. Therefore, using additional riser instrumentation would provide negligible benefit.

One commenter suggests that the final rule should be revised to implement systems addressing approaches for ensuring crew safety and access to the seabed wellhead. The commenter cautions that, for deep water operations (>5000 feet (1524 meters)), it is likely that a dynamically positioned MODU will sink away from the seabed location (wellhead) of a well that has blown out. Additionally, the commenter asserted that forcibly pulling a MODU off of a well that is blowing out may result in a far higher rush of hydrocarbons to the rig floor, with very serious implications for the safety of the crew and the subsequent blow-out events.

BSEE disagrees that revisions to the rule are necessary. We consider access to the wellbore, wellhead and associated top hole equipment to be a part of the evaluation required under the revised § 250.720(c). Under this provision, the operator is required to evaluate equipment needs when moving a drilling rig off a well prior to completion or permanent abandonment to ensure that an appropriate response to potential issues will be available. Regarding the commenter's concern related to dynamically positioned MODUs engaged in deep water operations, it is anticipated that none of the relevant Arctic OCS exploratory drilling operations will be in water depths greater than 5000 feet. However, if operational realities change, the regulations finalized here do address the commenter's concern, as the operator must evaluate equipment needs and ensure appropriate responses to issues (*e.g.,* MODUs sinking away from the wellhead) are available.

One commenter expressed concern with running a capping stack in shallow water, particularly installing a capping stack within the ''boil'' of a blowing out well. The commenter suggests that using a pre-positioned capping stack may be preferable.

The commenter's concern is addressed in this final rule. The ability to install the capping stack under expected conditions, including within the ''boil'' of a blowing out well, is required to be evaluated by the operator and presented as a part of their APD. BSEE agrees that there may be situations when the capping stack will not be an appropriate response to a well control event, which is why this is only one part of a series of well control measures proposed in the rule, including containment systems and same season relief well capabilities. Additionally, this final rule does not preclude the use of a pre-positioned capping stack as a part of an operator's proposal, and BSEE will evaluate such proposals on a case-by-case basis. To clarify, we revised the definition of Capping Stack to include one that is pre-positioned and may be utilized below a surface BOP when deemed technically and operationally appropriate, such as when using a jack-up rig with surface trees.

One requested BSEE consider relief well mooring patterns in advance, as the layout and installation of mooring systems may be complicated by the existing mooring system or by the inability to run mooring lines across the ''boil'' of a blowing out well.

BSEE does not agree that advance positioning of pre-set moorings or partially pre-set moorings for a relief well rig would be appropriate. The actual geometry of a well, including its

well depth, surface and downhole locations, wellbore trajectory and water depth, is needed to accurately identify where a rig and its moorings should be located to drill a relief well. Much of this information cannot be determined or predicted in advance of a loss of well control. It is preferable to decide on a relief well mooring location(s) and mooring pattern at the time of an actual blowout, when the appropriate surface and downhole locations, geometry, wellbore trajectory and water depth of a relief well/rig can been determined. The rule does, however, require that the operator describe its plans for execution of relief well operations at both the EP and APD stages.

One commenter stressed the importance of well and rig specific training. The commenter noted it is essential to undertake a detailed modeling of potential events so that potential issues can be recognized, mitigations developed, and crews properly and effectively trained.

BSEE agrees with the importance of the role a well-trained crew plays in achieving safe and professional drilling operations. We believe that the training requirements in our existing regulations already provide the basis for developing this type of crew. Section 250.1501, *What is the goal of my training program?,* requires training to ensure that employees and contractors engaged in well control, deep water well control, or production safety operations understand and can properly perform their duties. Section 250.1915, *What training criteria must be in my SEMS program?,* requires implementation of a training program developed in accordance with employee duties and responsibilities for use in the SEMS programs. These regulatory provisions require adequate training of workers specific to their positions at the relevant location and rig.

Two commenters assert the final rule should require the submittal of a well control plan.

Based on the limited information submitted with these comments, BSEE is assuming the commenter would like to see such a plan developed by an operator and submitted to BSEE as part of the approval of a well. Although BSEE agrees with the commenters that submittal of a well control plan would be of value to personnel safety and environmental protection, for such a plan to have meaningful input into actually controlling a well, the specifics of such a plan would need to be developed after a well control event. Therefore, BSEE does not agree that requiring a new plan as part of the approval of a well is appropriate. The actual response on the rig to a well control event is well specific and needs to be developed at the time of the event in order to capture the actual well depth, wellbore geometry, geology, mud weights, casing and/or liner setting depths, and wellbore properties (*e.g.,* pore pressure, fracture gradient, leak off data). Making assumptions for this information ahead of an actual event will not be of value in combatting a loss of well control.

It is important to note that BSEE already requires general well control plan type information in an operator's APD. In addition to discussing how a diverter system or a BOP will be used during an actual kick or loss of well control situation, the APD discusses general well control procedures (*e.g.,* drilling method, wait and weight method, concurrent method of circulating out a kick) that may be implemented during an actual event. If an actual event takes place, the general information included in the APD will be modified in the field to properly address actual wellbore conditions and geometries. Similar information is also already required at the EP stage through, § 550.213(f) example, the blowout scenario required by § 550.213(g), which addresses planning for response to a blowout, including surface intervention and relief well capabilities.

One commenter contends that the revised regulations would be more effective from the standpoint of management of human and environmental risk in the Arctic offshore if they focused on prevention and alternate methods instead of focusing on a relief well plan. The commenter asserted that prevention through prudent well design and operations should be the primary method for control and containment.

BSEE agrees with the commenter that prevention is an important component of control and containment, but disagrees with the comment that it would make response capability unnecessary. We believe the rule properly focuses on both prevention and response techniques, including relief well plans. Proper control of a well in an emergency is achieved through reliance on a wide variety of techniques that may be employed depending upon the circumstances, including use of a relief well according to the provisions of § 250.472, if needed. These include, but are not limited to: Use of proper operational procedures; safe work practices; well maintained and effective equipment, systems, and technologies; a comprehensive inspection/audit program; use of properly trained employees and contractors capable of performing their job duties within the constraints of the actual rig equipment; and implementation of a robust safety management system. All of these techniques, including a well thought out relief well plan, need to work together to ensure proper well control under all circumstances during drilling operations.

One commenter questioned whether a contractor bears a residual responsibility and/or liability for securing the downhole integrity of the well or the effectiveness of the well plugs.

BSEE notes the operator is the ultimately responsible party for all safety, operational, and environmental concerns during a drilling operation. However, any person performing an activity under a lease issued or maintained under OCSLA must comply with regulations applicable to that activity, is obligated to take corrective action, and is subject to civil penalties for a failure to comply. Under the requirements of § 250.107(a)(1) and (2), all operations on a lease must be performed in a safe and workmanlike manner, and work areas must be maintained in a safe condition. Accordingly, contractors can be held responsible for activities related to securing a well where they actually perform those activities.[23]

One commenter suggests that barrier requirements be qualified for the environmental conditions and time period used, for example, deep set versus shallow set plugs.

BSEE agrees that barriers, dual barriers and otherwise, need to be qualified for the environmental conditions and time period used. The barrier requirements included in this rule and in our existing regulations allow for such barriers to function properly at all times in the environmental conditions (*e.g.,* temperature, pressure, geologic and fluids) to which they are exposed during their operational life. Therefore, both the revisions to § 250.720 in the final rule and the existing BSEE regulations[24] are sufficient to ensure that plugs,

[23] For additional guidance on contractor liability, see BSEE's Interim Policy Document (IPD) No. 12–07, *Issuance of an Incident of Non Compliance (INC) to Contractors* (August 15, 2014), available at *http://www.bsee.gov/uploadedFiles/Issuance%20of%20an%20Incident%20of%20Non%20Compliance%20to%20Contractors.pdf*.

[24] *See, e.g.* regulations at 30 CFR 250.400 through 250.490, subpart D, Oil and Gas Drilling regulations; 250.500 through 250.531, subpart E, Oil and Gas Well-Completion regulations; 250.600 through 250.630, subpart F, Oil and Gas Well-Workover; and 250.1700 through 250.1754, subpart Q, Decommissioning Activities.

whether set deep in the well or at a shallow well depth, are qualified for the environmental conditions and time period used.

One commenter recommended revising proposed § 250.402(c)(2) because they claimed it introduces problems for some drilling platform choices, and because there is no basis for the assumption that the absence of a mudline cellar increases potential risk to the wellbore. The commenter argued that the uniform requirement for a mudline cellar poses special problems for a bottom-founded rig. The commenter also asserted the scope of the proposed requirement for mudline cellars will depend greatly on how areas of ice scour are identified, and suggested that ice scour analysis should be defined in the regulation to ensure objective and reasonable application.

Although BSEE disagrees with the commenter's claim that there is no basis for the assumption that the absence of a mudline cellar increases potential risk to the wellbore, we do agree there may be operational difficulties presented by a uniform requirement for a mudline cellar and did not intend this requirement to be overbroad in its application. The proposed language at § 250.402(c)(2) required the operator to use a mudline cellar in areas of ice scour, while allowing for the use of ''equivalent means of minimizing the risk of damage to the well head.'' To clarify this requirement, we are revising the language in proposed § 250.402(c)(2), as set out in the regulatory text of final § 250.720(c)(2). This revision clarifies that an operator may seek approval of an equivalent means to protect the well head and wellbore if it can also show how a mudline cellar would create operational risks. The operator must demonstrate that the equivalent means of minimizing the risk of damage to the well head and wellbore will meet or exceed the level of safety and environmental protection provided by a mudline cellar. Similar flexibility is provided through existing § 250.141.

Regarding the commenter's suggestion that ice scour analysis should be defined in the regulation, we disagree. BSEE has determined not to prescribe a means of analysis of scour data specific to any one technology to allow for the use of new technologies which may be used to determine ice scour (*e.g.*, satellite, or a currently unknown type of technology) in the future.

One commenter asserted there is no reasonable basis for concluding that ice collision damage to a well head would impair integrity of the well down at the level of a hydrocarbon zone. The commenter suggests the focus of the regulations should be protection against the loss of oil containment, best done with attention to barriers and plugging. The commenter acknowledged that although the proposed rule does allow ''equivalent means'' to a mudline cellar, no guidance is provided on what might be considered equivalent, and no equivalent alternative is readily apparent.

BSEE disagrees with the premise that protecting the well head should not be a focus of the regulations, nor do we agree that a well head compromised by ice collision would not impair the downhole integrity of the well. Having a mudline cellar in place to protect the wellhead provides an additional protection against a loss of well control and possible release of hydrocarbons to the environment. BSEE further notes that, as discussed in the previous comment, we have revised the language in final § 250.720(c)(2) to clarify what an operator should show when requesting to utilize an equivalent that minimizes risk to both the well head and the well bore under this provision. Additionally, alternative compliance measures may be approved under the requirements of § 250.141, as appropriate. As discussed throughout this preamble, we have included discussion on the criteria BSEE will consider to approve such measures in Section III.B.

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

BSEE proposed to add a new paragraph to existing § 250.418. Proposed § 250.418(k) requires operators conducting exploratory drilling operations on the Arctic OCS to provide, with their APD, information concerning how they will comply with the SCCE requirements of § 250.470. No comments were received on the proposed language, and the language is adopted without change, however the paragraph is now designated as paragraph (i) to conform to other, unrelated revisions to § 250.418 finalized in the Well Control Rule). See later in this Section for the discussion of comments on § 250.470 for BSEE's response to comments related to the SCCE requirements.

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

Existing § 250.737, finalized in the Well Control Rule, requires a 14-day testing frequency for the BOP hydrostatic pressure test. BSEE had proposed to revise existing § 250.447(b) to implement a 7-day testing frequency for the BOP hydrostatic pressure test for Arctic OCS exploratory drilling operations, increasing the frequency from the 14-day interval currently required for all OCS drilling operations (*see* NPRM, 80 FR 9934–5). BSEE received several comments on the appropriate interval for BOP pressure testing. Many commenters supported retaining the 14-day test cycle for various reasons, while others requested that BSEE require a 7-day test cycle for the Arctic assert that more frequent testing has not been proven to decrease reliability of the equipment and would improve safety and protection of the environment.

We do agree with the commenters' support for additional safety and protection on the Arctic OCS and have determined the current regulations improve safety and protection of the environment. As discussed in Section IV.A, *Summary of Key Changes from the NPRM,* BSEE has decided not to adopt the proposed 7-day testing interval and will maintain the same 14-day test cycle on the Arctic OCS as is required elsewhere on the OCS. We note that § 250.737(a)(4) allows for the District Manager to require more frequent testing if conditions (Arctic or otherwise) or the BOP performance warrant. Additionally, § 250.737(d)(9) requires a function test of the annular and ram BOPs every 7 days, between pressure tests, ensuring the BOP rams will function in all operating conditions.

Many commenters highlighted a lack of evidence that reducing the testing interval of the BOP systems from a 14-day test cycle to a 7-day test cycle would result in an increase of safety. These commenters asserted that more frequent pressure testing has not been shown to increase reliability of the equipment and expressed concerns that the more frequent test cycle would cause increased wear-and-tear and fatigue wear of the BOP components, increase the risk that the BOP system will be damaged during testing, increase the likelihood that a well control event could occur during testing, and unnecessarily shorten the drilling season. Several of the commenters also noted that existing BSEE regulations authorize BSEE to require additional testing frequency, if needed.

BSEE agrees. We are not aware of any reliable data that show that more frequent testing enhances the safety of operations. We also have concluded that there is evidence that frequent testing may increase some risks, as well as increase the time needed for operations. BSEE has determined that existing regulations for BOP hydrostatic pressure testing requirements will remain at the 14-day interval and provide for an

appropriate level of safety for exploratory operation on the Arctic OCS. Therefore, we have decided not to finalize the 7-day testing frequency requirement for exploratory drilling on the Arctic OCS.

Several commenters also asserted that a 7-day testing interval would directly conflict with BOP testing requirements finalized in the Well Control Rule for all operations on the OCS, and there is no basis for requiring different BOP testing requirements on the Arctic OCS. The commenters emphasized that BOP testing is not an Arctic-specific issue, as BOP performance is equally important regardless of where the operations are conducted. The commenters asserted that subsea temperatures in the Arctic are very similar to those encountered in deep water in the Gulf of Mexico at the seafloor and, similarly, BOPs operating onshore in the winter at negative temperatures are not subject to more frequent testing. Commenters asserted that, if BSEE requires the 7-day testing schedule for the Arctic OCS, then the question could be raised as to whether the 7-day testing schedule should be instituted for all OCS operations on the basis of greater safety. One commenter recommended that the regulations allow for the operator to demonstrate that the BOP equipment, elastomers, and hydraulic control fluid are suitable for the expected Arctic operating environment, including both surface and subsea conditions, with the specifications reviewed and approved by the appropriate regulatory agency.

BSEE generally agrees with the commenters. After considering all the information available, we have determined that the BOP hydrostatic pressure testing requirements will remain at the 14-day interval. We note that while our decision was based on public comments and available studies rather than the desire for uniformity for all OCS operations, the result is that BOP testing requirements will remain consistent for all oil and gas drilling operations on the OCS. BSEE is confident that the unique operating conditions on the Arctic OCS will be addressed, if needed, by the existing § 250.737 allowance for the District Manager to require more frequent testing if conditions or BOP performance warrant.

Several commenters expressed concern that BSEE did not provide adequate technical analysis or justification for proposing the 7-day BOP test cycle for Arctic OCS operations. These commenters emphasized that BSEE proposed changing the testing interval based only on Shell's voluntary reduction of the testing interval in 2012 and on a request from another organization for more frequent BOP testing. Many of the commenters also referred to research supporting less frequent BOP testing. These commenters asked whether BSEE has obtained other studies or additional information that would suggest more frequent BOP pressure testing will result in safer operations. Commenters noted that worldwide, except for the OCS, the standard for BOP pressure testing is 21 days, and that API RP 53 recommends 21 day BOP pressure testing.

BSEE agrees with the commenters on the importance of technical information and study on this issue. After considering all the available information, we have determined to retain the 14-day BOP testing interval. The proposed requirement for more frequent testing was based in part on how Shell conducted operations in 2012. The decision not to require a 7-day BOP testing interval, however, is based on public comments and available studies. We agree with the commenters highlighting conclusions reached by several studies supporting the decision to retain the 14-day BOP testing interval, including the 1999 Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology (SINTEF) study,[25] the follow up SINTEF study [26] released in 2001, and the study by Tetrahedron, Inc.,[27] which was the basis for the change in regulations (*see* 63 FR 29604, June 1, 1998) from a 7-day BOP test frequency to the current 14-day test frequency.

Regarding commenters' support for a 21-day testing interval, we have determined that available data does not support changes from the general 14-day testing interval at this time. BSEE is aware of concerns that the more frequently BOPs are tested, the more likely the equipment might wear out prematurely, and thus fail to operate properly when needed. Additionally, an operator that believes a different interval is warranted by special circumstances may seek approval from the District Manager of an alternative procedure in accordance with § 250.141 or a departure under § 250.142.

[25] Holand, Per, Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW, SINTEF, Trondheim, Norway, November 7, 1999.

[26] Unrestricted report, Deepwater Kicks and BOP performance, SINTEF, Final Report, July 2001.

[27] Reliability of Blowout Preventers Tested Under Fourteen and Seven Days Time Interval, Final Report, Tetrahedron, Inc, December 1996. Report available at *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Projects/Project-253/.*

What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations? (§ 250.452)

BSEE proposed to add a new performance-based section in Part 250 that would require real-time data gathering on the BOP control system, the fluid handling systems on the rig, and, if a downhole sensing system is installed, the well's downhole conditions during Arctic OCS exploratory drilling operations. In addition, the proposed provision would have required operators to transmit immediately the data during operations to an onshore location, identified to BSEE prior to well operations, where it must be stored and monitored by personnel who would be capable of interpreting the data and have the authority, in consultation with rig personnel, to initiate any necessary action in response to abnormal events or data. Such personnel must also have the capability for continuous and reliable contact with rig personnel, to ensure the ability to communicate information or instructions between the rig and onshore facility in real-time, while operations are underway.

Several comments were received on this section. As discussed in Section IV.A, *Summary of Key Changes from the NPRM,* BSEE is revising the proposed § 250.452 in response to comments received on the requirements. These revisions clarify the operator's responsibilities for complying with the RTM requirements. The revised proposed section requires operators to transmit data, as it is gathered, to a designated on shore location where it must be stored and monitored by qualified personnel who have the capability for continuous contact with rig personnel.

Several commenters recommended removing the RTM requirements from the final rule. One of the commenters suggested that RTM for a BOP Control System should not be considered as useful as RTM for drilling parameters or Measurement While Drilling (MWD) data feeds. Another of the commenters recommended removing the proposed requirement because it is being addressed in the Well Control Rule.

BSEE disagrees. Due to the harsh environment and remote nature of the Arctic, exploratory drilling on the Arctic OCS, absent additional precautions appropriate to the region, constitutes a significantly higher risk activity than conventional drilling operations in other regions, such as the Gulf of Mexico and southern California. Therefore, we have determined it is appropriate to require RTM as an

additional safety precaution for the BOP Control System, among others, as the BOP is one of the major safety barriers for preventing a loss of well control event. Additionally, we disagree that the RTM requirements can be removed from this final rule because the requirement is addressed in the Well Control Rule. The requirements finalized at § 250.452 are applicable to all exploratory drilling on the Arctic OCS, whereas the requirements finalized at § 250.724 in the Well Control Rule only apply to drilling operations using a subsea BOP or surface BOP on a floating unit, or high pressure high temperature (HPHT) drilling operations (*see* 81 FR 25888).

Two commenters recommended that BSEE wait to finalize the RTM requirements until the completion of the National Academy of Sciences Marine Board Study.

The Marine Board study report was released in May 2016 and is posted on the BSEE Web site.[28] The study report includes a recommendation for BSEE to pursue a performance-based regulatory framework by focusing on a risk-based regime that determines relevant uses of RTM based on assessed levels of risk and complexity. BSEE believes this rule meets the intent of that recommendation. It represents a balance between performance-based requirements and base-level requirements. BSEE will require basic RTM capabilities for exploratory drilling activities in the Arctic based on the applicable considerations of risk and complexity, as discussed above, but will require operators to assess their own particular operational risks and determine the specific parameters to monitor those risks. It is important to note that the Marine Board study is part of an ongoing research effort by BSEE to better understand RTM technologies and their potential use by industry and BSEE. BSEE completed an internal study on RTM in March 2014, which yielded preliminary recommendations on the use of RTM technology during drilling, completion, workover, and production operations and described possible scenarios in which BSEE could use RTM to enhance its regulatory oversight capabilities. BSEE also commissioned an outside study on RTM, which was completed in January 2014.[29] The outside study provided information and recommendations on several topics, including: (1) The current state/usage of RTM technology; (2) cost-benefit of RTM; (3) training for RTM; (4) critical parameters and operations to monitor with RTM; (5) condition monitoring using RTM; (6) regulatory approach (prescriptive vs. performance-based) for RTM; and (7) automation role for RTM. The Marine Board held the public workshop in April 2015 to review these two study reports and a summary of the workshop is posted on the Marine Board's Web site.[30] BSEE has carefully reviewed the comments received on the proposed rule and the other available information, and concludes that it is appropriate at this time to finalize the RTM provisions of this rule because existing information and wide-spread industry use supports the conclusion that RTM requirements enhance safe drilling operations.

One commenter suggested that the role of RTM in managing emergency situations should be assessed to understand the impact of human factors on performance.

BSEE agrees that human factors play an important role in an effective emergency response, and the way that data streams from programs, including RTM, affect the emergency response decision process should be anticipated and described in the operator's SEMS program. This is in line with API RP 75, which is incorporated by reference into the SEMS regulations and which specifically promotes the consideration of human factors in the design of a SEMS, including as an underlying SEMS principle (Section 1.1.2.n.), in the design of new and modified facilities (Section 2.3.5), in the conduct of hazards analysis (Section 3), in the crafting of operating procedures ''to minimize the likelihood of procedural error'' (Section 5), in the design of Safe Work Practices (Section 6), and in ensuring that critical equipment is easily accessible for critical tasks (Section 7). Ultimately, the operator is responsible for determining how to effectively integrate RTM and human factors into their emergency response and well control planning.

Three commenters expressed concern about the ability to continue operations in the event of a failure or interruption in the data link to shore. One of the commenters further stated that even when no failure or interruption occurs, RTM data will have a small lag time associated with it and will not be ''immediately transmitted.''

BSEE agrees it should not be necessary to cease operations just because of a temporary loss of the RTM data feed. In this type of situation, the operator should have the ability to gather and record the data in the control room of the offshore unit and transmit the data to shore once the data feed is restored. To clarify this point, we deleted the word ''immediately'' from the proposed text and revised the first sentence of final § 250.452(b) to state that during well operations, you must transmit the data identified in paragraph (a) as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. Additionally, to clarify that in the event of a failure or interruption of the datalink the operator should continue collecting RTM data, we added qualifying language to § 250.452(a), providing that the monitoring system must be ''independent, automatic, and continuous'' to ensure the operator is able to transmit data, even if not immediately, in a timely and appropriate manner. *See* Section IV. A for a complete discussion of changes from the proposed regulatory text of § 250.452.

Three commenters recommended that operators should have the flexibility to develop a performance-based approach to state in their EP or APD which functions will be monitored.

We agree with the comment and have deleted ''all aspects of'' from § 250.452(a) to allow flexibility for a more performance-based approach. An operator can explain which functions of the identified systems will be monitored in their EP or APD.

One commenter recommended the parameters of RTM should be more defined.

BSEE disagrees. We determined that defining exact parameters in this regulation would be overly prescriptive. BSEE believes guidance documents and industry standards are the best way to define important parameters for RTM as this technology continues to advance.

Several commenters cautioned that the proposed RTM requirements shift operational decision making away from operators and rig personnel and recommended that the language be clarified to affirm that it is the primary responsibility of onboard rig personnel to monitor operations.

BSEE agrees that command and control decision making is typically the primary responsibility of the onboard rig personnel, and the onshore RTM personnel should in most, if not all, scenarios only function in an advisory capacity. It was not BSEE's intent, nor

[28] Report is available at *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Projects/Project-740.*

[29] Summary available at *http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/Projects/Project-707.*

[30] Summary available at *http://www.trb.org/main/blurbs/173606.aspx.*

does BSEE agree that the proposed rule text implied, that the RTM requirement would result in a shift of responsibility away from onboard rig personnel. To clarify this point, we deleted the proposed text in § 250.452(b): ''. . . and who have the authority, in consultation with rig personnel, to initiate any necessary action in response to abnormal data or events.'' This revision makes clear that the onboard rig personnel should continue to have the primary responsibility to monitor operations and act accordingly. The RTM monitoring requirements seek to help improve, not disrupt, the ability of onboard rig personnel to monitor operations and assess and mitigate risks. *See* Section IV.A for a complete discussion of changes from the proposed regulatory text of § 250.452.

One commenter asked whether there is an implicit requirement for contractors to maintain duplicate records, or ascertain if the required RTM is being undertaken, and to suspend operations if not.

The operator is responsible for overall compliance with the regulations during operations, and the primary monitoring and record-keeping responsibility belongs to the operator. However, under existing § 250.146, a contractor actually performing operations also has the responsibility to comply with regulations applicable to those operations, as does anyone actually performing operations carried out under an OCS lease. Responsibilities for contractors are further clarified in BSEE's Interim Policy Document (IPD) No. 12–07 (August 15, 2012), ''Issuance of Incident of Non Compliance (INC) to Contractors.'' The IPD clarifies that any person performing an activity on a lease issued under OCSLA is responsible for compliance with regulations applicable to that activity, and can be held accountable for noncompliance. Additionally, under existing § 250.1914, an operator's SEMS program must contain appropriate detail in the bridging documents between the operator and any contractors, including the contractor's roles and responsibilities with regard to RTM. Accordingly, a contractor's responsibility for compliance with the RTM provisions depends upon the contractor's role with respect to carrying out the RTM requirements.

One commenter noted that BSEE will be exposed to proprietary and confidential information when they visit an operator's Real Time Operations Center, and will need to be bound by confidentiality agreements.

BSEE agrees that it must protect proprietary information in accordance with Federal law. As Federal regulators, BSEE personnel routinely work with proprietary and confidential information in the course of carrying out their official duties, so this is not a unique issue to RTM. We will employ the same safeguards, training and accountability measures, and oversight to comply with all Federal laws for protecting proprietary and confidential information obtained pursuant to these provisions. To further clarify, we note that BOEM and BSEE routinely protect proprietary information in accordance with existing §§ 250.197 and 550.197, *Data and information to be made available to the public or for limited inspection,* and requirements of controlling law such as the Trade Secrets Act.

One commenter expressed concern that the USCG has not been involved in the development of the RTM requirements, as they have some jurisdiction over these rigs and this monitoring requirement could impact other rig functions and present possible cyber and security threats.

BSEE acknowledges the commenter's concern but disagrees with the basis of the comment. We have shared the proposed and finalized regulatory requirements for RTM, and all other requirements, in this rulemaking with the USCG as part of the interagency review process required by E.O. 12866. Additionally, we have an existing Memorandum of Agreement (MOA) with the USCG discussing shared regulatory responsibilities on MODUs. MOA OCS–08 *Mobile Offshore Drilling Units (MODUs)* (June 4, 2013) [31] addresses issues related to shared RTM responsibilities between USCG and BSEE such as station keeping and dynamic positioning. Although MOA–OCS–08 does not specifically address RTM, it does address the systems and subsystems being monitored. Regarding the cyber risk, because the RTM requirement relates only to remote monitoring of operational aspects and not remote control, there should be reduced risk of the RTM system becoming a significant cyber vulnerability. However, BSEE and the USCG agree there are many aspects of modern offshore oil and gas operations that pose a cyber risk. This topic is being considered outside the scope of this rulemaking effort.

One commenter questioned whether BSEE will expect RTM to reduce the number of BSEE inspectors physically present offshore 24/7 during drilling activity.

The finalized requirements of § 250.452 do not address how much of an inspection presence BSEE will maintain. The variability of inspection presence on any facility is dictated by internal BSEE policy, which accounts for many factors, including inspection resource availability and the relative risk of the operations. BSEE may take into account the availability of RTM among those considerations.

One commenter cautions that RTM technology will increase the current level of complexity in the BOP and suggests that the interaction with software should be addressed through a formal qualification process. The commenter further asserted that the maintenance and repair of BOPs will need to be done to Original Equipment Manufacturer (OEM) recommendations unless otherwise directed by BSEE, but the proposed regulations do not define how this will be enforced.

BSEE agrees with the commenter that RTM technology will increase the complexity of BOPs, but has determined the commenter's concern has been addressed by the requirements finalized in the Well Control Rule at § 250.732, *What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?.* These requirements apply to all BOPs and include a requirement under § 250.732(d)(8) that the BAVO report to BSEE include ''[a] comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.'' Also, § 250.732(d)(3) requires that the BAVO report to BSEE include a description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.

One commenter suggested that qualifying of BOP components for the actual operating conditions through appropriate testing and qualification plans should be extended beyond the rams and shear tests, and all scenarios should be considered.

BSEE disagrees. While it would be ideal to be able to test all the possible forces a BOP could experience when qualifying BOP components, this is usually not practical in a testing laboratory setting. Accordingly, calculations are typically permitted to supplement the testing results and account for the full range of forces that

[31] Available at *http://www.bsee.gov/BSEE-Newsroom/Publications-Library/Interagency-Agreements/.*

were not otherwise practical to simulate.

What additional information must I submit with my APD for Arctic OCS exploratory drilling operations? (§ 250.470)

BSEE proposed to add a new § 250.470, requiring operators to provide Arctic OCS-specific information with their APDs for exploratory drilling. The proposed informational requirements in the new section would be necessary to inform BSEE's evaluation of APDs for Arctic OCS exploratory drilling operations.

Several comments were received on this section. BSEE has evaluated the comments and determined that, with the exception of various technical edits, the substantive provisions of § 250.470 are finalized as proposed.

One commenter recommended that § 250.470 should include a requirement for operators to submit corrective action plans associated only with rectifying any deficiencies in the drilling unit or equipment that have been previously identified by a BSEE inspector on an Incident of Noncompliance (INC).

BSEE disagrees. The regulatory requirements of § 250.470 provides that drilling units and equipment may operate elsewhere outside of the Arctic drilling season, and the rigs may need repairs or maintenance before beginning operations on the Arctic OCS. Accordingly, the operator will need to demonstrate it is fully prepared to drill on the Arctic OCS prior to each drilling season. BSEE inspections are only one aspect of ensuring safe operations. The operator is responsible for ensuring the safety of their equipment by conducting on-going maintenance and repairs, and the operator must identify needed repair and maintenance for the drilling unit and equipment independent of the issuance of any INCs.

One commenter asserted that the APD provisions require an operator to resubmit a significant amount of information that is already included with the EP and the IOP.

BSEE disagrees. The additional information to be submitted with an APD under § 250.470 is not a requirement to re-submit duplicative information. BSEE expects that when the operator submits the APD, it will by then have a detailed plan that will include information on the same topics touched on in the IOP and EP, but that was not available at the time the IOP or EP was submitted. This may include information such as the identity of equipment and vessels to be used, dates of planned operations, and additional information on how the equipment and vessels would be designed for and be capable of performing in Arctic OCS conditions. To the extent that the operator has already provided necessary information in its approved EP, it may reference that information or recreate it with little burden.

One commenter supported the proposal to require detailed Arctic-specific information in the APD, but cautions that this information will be provided too late in the Department's review and approval process to provide adequate opportunity for the public to review and comment on this information. The commenter recommended BSEE require the inclusion of this important technical data as part of the IOP and EP review, in which outside parties may participate. The commenter recommended, as an alternative if BSEE prefers to require this important information only in the APD application, that the regulations be revised to include an opportunity for ''outsiders'' to participate in APD review.

BSEE agrees with the commenter's statements on the importance of the APD, but disagrees with requiring the same information as part of the IOP and EP submissions. The IOP, EP, and APD are intended to allow the operator an opportunity to provide increasingly detailed information that is pertinent to each stage of the exploratory drilling operation approval process. Much of the information submitted with the APD is not expected to be available or relevant when submitting the IOP or EP.

While the commenter's suggestion regarding who should be able to participate in the review of the APD is unclear, we assume it is referring to the public. Since much of the information submitted with an APD will likely contain proprietary information, BSEE does not believe it would be appropriate to involve the public directly in the APD review process. However, we note that the regulatory requirements for the IOP, EP, and APD require the operator to make informational copies available to the public with the proprietary information removed. Operators are required to submit an informational copy of their APD, which will be publicly available on the BSEE.gov Web site: (*http://www.data.bsee.gov/homepg/data_center/plans/apdcombined/master.asp*). The APD is a technical document that explains how an operator will safely drill a well. As part of BSEE's review of the APD, BSEE ensures the APD is consistent with the approved EP, and, if not consistent, the operator must revise the APD or the EP, as appropriate. The EP process affords input during the review process from Federal agencies, State and local governments Tribal governments, ANCSA Corporations, as well as the public. The transparency of both the APD process and the related IOP and EP processes (as described earlier in connection with comments on § 550.206) allow for public review and input throughout the process, as appropriate. Therefore, an additional specific public review process at the APD stage is redundant and unnecessary.

One commenter requested, in addition to the information required under § 250.470(c)(8) and (d), that BSEE require operators to submit documentation describing the criteria they would use for triggering site abandonment due to ice, and an organization chart of the operator's own personnel and subcontractors involved in such an operation. The commenter suggested that the criteria should be defined in quantities easy to observe and measure and should be linked to the operational mode of the MODU and its capacity as defined in the Fitness Requirements of former § 250.417(a). (The Well Control Rule removed and reserved former § 250.417 and moved the contents of that section to new § 250.713.) The commenter recognized that the criteria are indicated in EP requirements under § 550.220(c)(2)(iii). However, the commenter asserted the criteria are not clear because terminology related to ice management is inconsistently applied throughout the proposed regulations. The commenter referenced additional details regarding such criteria found in clause 17 of ISO 19906 (incorporated by § 250.470(g) in API RP 2N Third edition), but which the commenter asserted should be clarified in the rules rather than through IBR.

BSEE disagrees, as the provisions finalized at § 250.470 require the operator to present the required criteria for site abandonment due to ice in a measurable quantity and are in accordance with the Fitness Requirements in paragraph (a) of § 250.713, *What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?.* Section 250.470(c)(7) requires that the operator's APD include information on well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of a well, which must include specific information on when and how the operator plans to abandon the well and how the Arctic OCS specific requirements of paragraph (c) of final § 250.720, *When and how must I secure a well?,* will be met. These provisions are specific to Arctic OCS exploratory

drilling operations and necessarily cover abandonment due to ice. Additionally, § 250.470(d)(2) requires that the operator to include with its APD a detailed description of weather and ice forecasting capabilities for all phases of the drilling operation and plans for managing ice hazards. Similarly, § 250.470(g) requires compliance with API RP 2N Third Edition, which is largely identical to the standard identified by the commenter, including a description in the APD of how the operator will use relevant best practices included therein. The commenter references the EP requirements set forth in § 550.220(c)(2)(iii), which require the operator to include a description of its weather and ice forecasting and management plans, including the operator's procedures and thresholds for activating ice and weather management systems. The EP and APD requirements are similar, but implicated at different stages of the approval process and utilize different, but similar, terminology. The EP is intended to provide the operator the opportunity to present its overall plan for operations, and the APD is the technical document that provides the operator the opportunity to present details regarding how the plan will be implemented.

The commenter does not explain why requiring the submission of an organization chart would help BSEE's oversight efforts. If conditions require site abandonment, BSEE would deal directly with the operator or the operator's representative to address the situation. The operator would be responsible for directing its personnel and contractors, as appropriate.

One commenter recommended that the APD include a requirement for a written well control plan and evidence of a contract with a well control expert. The commenter asserted that, although written well control plans and contracts with well control experts are industry standard, like other important practices, this minimum standard should be codified in regulation so short-cuts are not taken. The commenter recommended that the Arctic emergency well control plan include information regarding the primary rig, SCCE, secondary relief well rig, and additional well barriers. The commenter further recommended that the well control plan should be site-specific and appropriate for Arctic OCS conditions.

BSEE disagrees with the recommendation to require a written well control plan. BSEE does not require a well control plan because it is the responsibility of the operator to determine how best to address these requirements and ensure they have the appropriate equipment available, the contracts in place, and their personnel properly trained. Additionally, the regulations finalized in this rulemaking build on our existing regulations to ensure that operators address the unique Arctic OCS operating environment in a manner that is site-specific and appropriate for Arctic OCS conditions. Specifically, BSEE has existing well control requirements under various provisions of the Well Control Rule, requirements for diverters and BOPs under § 250.416 and other sections of the Well Control Rule, and information requirements for MODUs under § 250.713 of the Well Control Rule. Existing § 250.713 requires operators who plan to use a MODU to drill to ''provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location.'' BSEE has training requirements under part 250, subpart O, *Well Control and Production Safety Training,* with additional training requirements under § 250.1915, as part of SEMS requirements. Further, § 550.213(g) requires submission of a blowout scenario as part of any EP that must address issues such as surface intervention and relief well capabilities. Likewise, the finalized provisions at § 550.220(c)(3) and (4) require Arctic OCS operators to describe in their EPs their plans for complying with the SCCE and relief rig requirements. Accordingly, BSEE believes that the combination of this rule and existing regulations adequately addresses the proposed function of a well control plan.

Paragraph (a), Fitness for Service

Paragraph (a) requires operators to submit a detailed description of the environmental, meteorological and oceanic conditions expected at the well site(s); how their equipment, materials, and drilling unit will be prepared for service in those conditions, and how the drilling unit will be in compliance with the requirements of § 250.713. The information requested by this proposed section for drilling units is not in addition to the requirements of § 250.713, but rather is designed to make clear that, to satisfy the fitness requirements of § 250.713, operators would need to provide details regarding Alaska OCS conditions.

One commenter recommended the Fitness for Service description should illustrate how the drilling unit and its major components can perform in the anticipated conditions of the location and season under which it is expected to operate.

BSEE agrees with the comment and notes that the finalized provisions at § 250.470(a)(2) address the commenter's concern. Paragraph (a)(2) of § 250.470 requires the operator to submit a detailed description of how the equipment, materials, and drilling unit will be prepared for service in the environmental, meteorological, and metocean conditions expected at the well site and how the drilling unit will be in compliance with the provisions of existing § 250.713. Existing § 250.713 requires the operator to provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand.

One commenter requested clarification on the contractor's or equipment supplier's responsibility for compliance with the specifications to be provided under § 250.470(a)(2). The commenter questioned whether it is reasonable to hold a party other than the applicant for the APD responsible when the selection of the equipment and contractor is presumably based on the APD applicant's foreknowledge of the conditions that can be reasonably expected during operations.

BSEE disagrees. Only the party responsible for submitting the APD is responsible for satisfying the requirements of § 250.470(a)(2) related to the contents of its APD. Whether a contractor is responsible for satisfying those requirements depends on the scope of activities performed by the contractor (*i.e.,* are they responsible for the APD submission?). That said, any party actually performing activities on the OCS is responsible for complying with all applicable requirements in conducting those activities, including any conditions or terms of approved plans and permits. Expectations for anyone performing activities on an OCS lease are clearly established in existing regulations at paragraph (a) of § 250.107, *What must I do to protect health, safety, property and the environment?.* Responsibilities for contractors are further clarified in BSEE's IPD No. 12–07 (August 15, 2012), ''Issuance of Incident of Non Compliance (INC) to Contractors.'' The IPD states BSEE's expectations that all operations be performed in a safe and workmanlike manner and that work areas be maintained in a safe condition. It reiterates that the primary focus of enforcement actions continues to be the lessees' and operators'; however contractors performing regulated activities can be held responsible for

compliance with the regulations in their performance of those activities. The IPD establishes the factors BSEE will consider in determining whether to issue INCs to contractors. Accordingly, the scope of a contractor's responsibility for regulatory compliance depends upon the scope of activities performed by that contractor.

Paragraph (b), Well-Specific Transition Operations

Paragraph (b) requires operators to submit with the APD a detailed description of all operations necessary in Arctic OCS conditions for well-specific transition operations. BSEE is requiring details about all of the activities necessary to begin and end drilling operations, and to transition between drilling operations and being under way. Finally, BSEE is requiring information regarding any specific repair and maintenance plans for the drilling unit and equipment associated with commencement or completion of drilling operations. All of the required information would facilitate BSEE's understanding of an operator's program and ensure that the operator complies with lease stipulations, EP conditions, and other permitting requirements.

One commenter recommended that BSEE remove paragraph (b) of § 250.470 because the information requested covers aspects of operations which are regulated by the USCG and do not fall under the jurisdiction of BSEE or BOEM. The commenter alternatively requested that, if BSEE does not delete the paragraph, BSEE provide clarification as to what value will be gained from the information provided, as the agency has no authority over the activities on which it seeks information (for example, daily maintenance activities on vessels and rigs, including diesel engine maintenance routines, greasing routines on cranes, and other basic maintenance).

BSEE disagrees with the commenter regarding removing the noted paragraph, but will explain the value to be gained from the required information. First, the examples the commenter cites, such as diesel engine maintenance routines and ''towing,'' are not required under § 250.470(b). Second, the information requested by BSEE under § 250.470(b) relate directly to operations within the Bureau's authority under OCSLA. For example, 43 U.S.C. 1332(6) declares that ''operations in the [OCS] should be 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, spillage, 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.'' Under 43 U.S.C. 1334(a), the Secretary has the authority to ''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].'' Section 1348(b)(2) imposes a duty on lessees and operators to ''maintain all operations . . . in compliance with regulations intended to protect persons, property, and the environment on the [OCS].'' The information requested under § 250.470(b) will help BSEE to fulfill its mandate under OCSLA by ensuring that all operators are prepared to conduct drilling operations in as safe a manner as possible, especially given the challenges and fragility of the Arctic environment.

Paragraph (b) of § 250.470 requires that the information accompanying an operator's APD must include a detailed description of all transition operations necessary in Arctic OCS conditions to begin and end drilling operations and also requires a detailed description of repair and maintenance plans. Although USCG and BSEE share certain aspects of regulatory oversight of operations on MODUs, BSEE is not requesting information under another agency's jurisdictional authority. First, the information described above relates to matters within the scope of operations overseen by BSEE rather than USCG (*i.e.,* beginning and concluding drilling operations). Further, while the planning necessary to assure fulfillment of OCSLA's mandates in connection with the identified operations may implicate some activities, such as the operation of vessels which are regulated by other Federal agencies, it also informs the Department's oversight functions. Such activities can result in damage to operational equipment critical to DOI-regulated drilling activities, which can in turn compromise, reduce, or force modifications to approved operational or safety capabilities and equipment. Similarly, they can give rise to changes to approved operational schedules, which in the Arctic are particularly critical in light of unique considerations arising from the limited open water season, the timing of recession and encroachment of sea ice at drill sites, marine mammal migrations, and subsistence activities, among other considerations. Agency regulations have long recognized the need to obtain, through the planning process, information touching on activities outside of the Department's direct regulatory jurisdiction but which is relevant to the regulation of operations within its jurisdiction.[32] BSEE needs the requested information to ensure safety of the rig, operation-critical equipment, and personnel, during transitions and while engaged in operations. This information will ensure that potential issues with well-related equipment are addressed.

Paragraph (c), Well-Specific Drilling Objectives and Contingency Plans

Paragraph (c) requires operators to submit ''[w]ell-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well.'' Whereas the corresponding provisions of the finalized IOP regulations and current EP regulations at § 550.211 relate more broadly to the objectives and timelines of the overall proposed exploratory drilling activities, this provision would require an operator to provide ''well-specific'' information at the APD stage.

One commenter requested that BSEE delete § 250.470(c), reasoning that the contingency plans for temporary abandonment are out of place in this section or at the time in the planning process the section addresses. The commenter asserted that the information requested is highly sensitive and has little nexus to any of BSEE's regulatory authority.

BSEE disagrees. Temporary abandonment is a well operation and is under BSEE authority.[33] Accordingly, BSEE currently has regulations regarding temporary abandonment at §§ 250.1721 through 250.1723. These regulations establish the nationally applicable requirements for how to temporarily abandon a well. The finalized requirements under § 250.470(c) address Arctic-specific considerations related to temporary abandonment, including, among other issues, well-specific contingency plans for temporary abandonment due to ice encroachment. The information supplied under this section will require operators to engage in safety-critical

[32] *See, e.g.,* 30 CFR 550.224 (requiring description in EP of the support vessels, offshore vehicles, and aircrafts you will use to support your exploration activities, including maps of travel routes and methods for transportation of fluids, chemicals, and wastes); 550.257 (same for Development and Production Plans (DPPs) and Development Operations Coordination Documents (DOCDs)); 550.225 (requiring description in EP of onshore support facilities to be used to provide supply and service support for the proposed exploration activities); 550.258 (same for DPPs and DOCDs).

[33] *See, e.g.,* 43 U.S.C. 1332(6), 1334(a), 1340(g), 1348(b)(2).

advanced planning regarding when and how the operator would temporarily abandon the well, and will provide BSEE with advance notice of and an opportunity to review those plans. The operator must specifically address how the rig would be moved off location; how the well would be secured; and how the operator will meet the finalized requirements in § 250.720(c) to ensure that equipment left on, near, or in a wellbore is protected. This provision requires information that is critical for BSEE to have to fully evaluate the APD in accordance with its mandates of safety and environmental protection under OCSLA in the challenging Arctic environment. The APD includes the specific details of how the operator will conduct the operations proposed in the EP including, if applicable, contingency plans for temporary well abandonment. The APD is submitted at a point in the planning and approval process at which the operator will have more complete and detailed information specific to the well locations and operations being proposed. With regard to the sensitivity of the data, BSEE will handle any proprietary or confidential information obtained pursuant to this provision in compliance with applicable law, including § 250.197 and the Trade Secrets Act.

Paragraph (d), Weather and Ice Forecasting and Management

The performance-based provision at paragraph (d) requires an operator to submit: A detailed description of its weather and ice forecasting capability for all phases of the drilling operation, including: ''How [it] will ensure the continuous awareness of potential weather and ice hazards at, and during transition between, wells;'' its ''plans for managing ice hazards and responding to weather events;'' and verification that it has the capabilities described in its EP. Operators can verify that they have the capabilities described in their EP by providing appropriate supporting documents (*e.g.,* contracts) for the forecasting and ice management capabilities.

One commenter requested that BSEE strike § 250.470(d), as the information sought in this paragraph is already contained in an operator's Critical Operations and Curtailment Plan (COCP) and Ice Management Plan and should not be duplicated as part of the APD process. The commenter asserted that weather and ice forecasting and monitoring are not well site specific and are not well suited as APD requirements.

BSEE disagrees. It is not BSEE's intent to have the operator submit information that it has already submitted to BOEM or BSEE under other requirements. Rather, the purpose of requiring an operator to submit information on ice and weather forecasting with the APD is to allow an opportunity, if needed, to update and supplement any information already submitted with additional details and information that was not available when the information was submitted previously. BSEE notes the information requested with an APD is not duplicative, and in addition to updating information, the operator is also required to address several new considerations, including how they will ensure continuous awareness of weather and ice hazards at, and during transition between, wells. To the extent that the requested information has been submitted previously, such submissions can be relied upon by reference.

Paragraph (e), Relief Rig Plan

Paragraph (e) requires operators to provide, with their APD, information concerning how they will comply with the relief rig requirements of § 250.472. No comments were received on this provision, and it is finalized as proposed. See below in this Section for the discussion of comments on § 250.472 for BSEE's response to comments related to relief rig requirements.

Paragraph (f), SCCE Capabilities

Paragraph (f) requires operators provide with their APD a statement that the operator has a contract with a provider for SCCE, which is capable of controlling and/or containing a WCD as described in the operator's BOEM approved EP, when proposing to use a MODU to conduct exploratory drilling operations on the Arctic OCS. The information requirements of paragraph (f) include:

1. A detailed description of the operator's or its contractor's SCCE capabilities. The description must include operating assumptions and limitations and information demonstrating that the operator would have access to and the ability to deploy such equipment necessary to stop or capture the flow of an out of control well. This description would allow BSEE to verify the location and availability of this equipment for compliance with § 250.471. This section also requires a detailed description of the operator's ability to evaluate the performance of the well design to determine how it can achieve full shut-in without having reservoir fluids discharged in the environment.

2. An inventory of the equipment, supplies, and services the operator owns or has a contract for locally and regionally, including the identification of each supplier. This information is important because BSEE would need to verify the existence, condition, and location of the equipment that the operator describes in its plans.

3. Where SCCE capabilities are obtained through contracting, proof of contracts or membership agreements with cooperatives, service providers, or other contractors, including information demonstrating the availability of the personnel and/or equipment on a 24-hour per day basis during operations below the surface casing.

4. A description of the procedures for inspecting, testing, and maintaining SCCE. SCCE is intended to be standby equipment. This provision allows BSEE to verify that the operator, or contractor, has procedures in place for inspecting, testing, and maintaining the equipment so that it would be ready for use, if necessary. Operators are already required under existing regulations at § 250.1916 to retain the information requested by this new paragraph. The new provision requires that operators who propose to conduct exploratory drilling on the Arctic OCS submit this information in conjunction with their APD.

5. A description of the operator's plan to demonstrate that personnel are trained to deploy and operate the equipment and that these personnel would maintain ongoing proficiency in source control operations. Standby crews who are not used regularly to perform their dedicated functions would not develop the necessary skills unless they are properly trained, and would not maintain those skills unless that training is reinforced by practice. It is therefore imperative that the operator demonstrate that these personnel have a plan for acquiring, and the ability to maintain, the proficiency necessary to respond when called upon. This requirement would allow BSEE to review those plans and verify that the proficiencies have been acquired and would be maintained.

One commenter suggests that the final rule require operators to submit a detailed plan demonstrating their ability to fully respond to a blowout within three days.

BSEE notes the final rule does require all operators conducting exploratory drilling operations on the Arctic OCS to have in place response plans demonstrating their ability to fully respond to a blowout, beginning within 24 hours after loss of well control. Specifically, revised § 250.471(a) requires that a capping stack be available and positioned to arrive at the

well within 24 hours after a loss of well control, and a cap and flow system and a containment dome be positioned to ensure they will arrive at the well location within 7 days after a loss of well control. Revised § 250.472 requires that any time the operator is drilling below or working below the surface casing it must have access to a relief rig, positioned so that it can arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control. Paragraphs (c)(3) and (4) of § 550.220 require operators to describe in their EP how they will comply with these requirements, and § 250.470(e) and (f) impose similar requirements for APDs. When added to existing regulations (*e.g.,* § 550.213(g)), BSEE has determined that these provisions will provide a reasonable level of environmental protection. BSEE does not agree that a uniform prescriptive three-day response plan is necessary or appropriate. There are many specific requirements in the final rule that will ensure that operators have access to equipment to quickly respond to losses of well control. Such responses will likely depend upon the specific facts and circumstances related to the loss of well control incident at hand and will not benefit from the suggested uniform requirement for a three-day response plan.

One commenter suggests changing the phrasing in § 250.470(f)(2) from ''local and regional'' in regards to the availability of SCCE, supplies, and services, to ''in-region'' and ''out-of-region'' to match common usage in Alaska (see 18 AAC 75.495) and to match oil spill response industry standard terminology.

BSEE disagrees. The provision at § 250.470(f)(2) ensures that the operator has the access to required SCCE within the timeframes established in § 250.471. The terms ''local and regional'' are used to reinforce that the equipment needs to be in proximate location to meet those standards. BSEE declines to adopt terms of art that may be perceived to have different meanings or connotations.

One commenter requested that BSEE remove § 250.470(f). The commenter asserted that operators should not have to provide this information in the context of each individual APD, as the information requested in paragraph (f) is largely duplicative of information provided elsewhere during the regulatory process. The commenter specifically points to information requested for the EP and IOP.

BSEE disagrees. As discussed above, the requirements of this section, or any provision of § 250.470, are not intended to require operators to resubmit information already submitted to BOEM or BSEE. Rather, the operator is expected to update and supplement the information already submitted and provide more specific or detailed information that was not available when it submitted information for the IOP and EP. To the extent that the operator intends to rely on information already submitted in previously approved submissions, it can do so by reference.

Paragraph (g), API RP 2N, Third Edition

Paragraph (g) requires that operators explain how they utilized API RP 2N, Third Edition, in planning their Arctic OCS exploratory drilling operations. Since the requirements of this final rule are limited only to exploratory drilling operations, operators would not be expected to provide an explanation of how they utilized the entire API RP 2N, Third Edition. This performance-based requirement is limited to those portions of that document that are specifically relevant for exploratory drilling operations. BSEE excludes the following sections of API RP 2N, Third Edition, from incorporation:

1. Sections 6.6.3 through 6.6.4;
2. The foundation recommendations in Section 8.4;
3. Section 9.6;
4. The recommendations for permanently moored systems in Section 9.7;
5. The recommendations for pile foundations in Section 9.10;
6. Section 12;
7. Section 13.2.1;
8. Sections 13.8.1.1, 13.8.2.1, 13.8.2.2, 13.8.2.4 through 13.8.2.7;
9. Sections 13.9.1, 13.9.2, 13.9.4 through 13.9.8;
10. Sections 14 through 16; and
11. Section 18.

One commenter supported the incorporation of API RP 2N Third Edition, but disagreed with the exclusion of three sections. The commenter first opposed the exclusion of API RP 2N clauses 6.6.3 (Ice Gouge) and 6.6.4 (Strudel Scours). The commenter suggests BSEE should consider the possibility of not being able to permanently plug the well before the next open water season, and that by having ice gouge statistics it would also be possible to calculate the actual impact risk to a well head. The commenter also questioned excluding section 13.2.1 (Design Philosophy) and recommended BSEE include a statement that when there is overlap between the requirements in API RP 2N Third Edition and BSEE and/or USCG regulations, the regulatory requirements have precedence.

BSEE carefully considered which sections of API RP 2N Third Edition to incorporate in this rulemaking and determined that certain portions of API RP 2N are not relevant to the exploration stage. Regarding the commenter's first concern with exempting API RP 2N sections 6.6.3 and 6.6.4, the regulations finalized at § 250.470(c) directly address protecting equipment left on, near, or in a wellbore, including protecting the well head and preventing or mitigating threats to the down-hole integrity of the well and well plugs. These regulations are tailored specifically to exploratory drilling operations on the Arctic OCS from MODUs and jack-up rigs, and BSEE determined that sections 6.6.3 and 6.6.4 were therefore not appropriate for incorporation. The commenter's second concern is addressed in § 250.470(g), which requires an operator to comply with the incorporated requirements of API RP 2N ''Where it does not conflict with other requirements of this subpart''.

One commenter also recommended including API RP 2N Third Edition sections 6.6.3 and 6.6.4, as there is evidence of ice gouging in several locations within the Arctic OCS, which would impact a multi-year drilling program. The commenter asserted that ice gouging should be considered for subsea structures likely to be left over winter, and that strudel scours are widespread along coastal river mouths and should be surveyed as part of planning for an exploratory drilling program in state waters. The commenter also recommended that sections 13.9.6 (Inspection and Maintenance), 13.9.7 (Planning and Operations), and 13.9.8 (Ice Management Plan) be included in the final rule, as they appear to provide a better basis for safe operation than the proposed regulations. The commenter also asked BSEE to consider retaining section 15 (Topsides), as there are a number of issues surrounding winterization of topside structures not under the authority of the USCG, such as wind breaks and insulation of manned work spaces and walkways, and winterization of drilling hydraulics and meters.

BSEE disagrees. Sections 6.6.3 and 6.6.4 were excluded because they address different types of conditions for ice gouging and/or scouring than are anticipated to occur during the Arctic OCS open water drilling season. To the extent the commenter is concerned about facilities remaining on the seabed in connection with multi-year drilling

programs, §§ 250.720(c) and 250.470(c) directly address these issues. BSEE also notes that under its OCSLA authority, it does not have jurisdiction over well control operations on State submerged lands. BSEE has authority under the CWA over oil spill response plans related to operations seaward of the coastline, including on state submerged lands. 33 U.S.C. 1321(j)(5); E.O. 12777; 30 CFR part 254, subpart D. In addition, existing BSEE regulations address drilling in frontier areas and include specific requirements related to Arctic OCS conditions, such as ice-scour areas and subfreezing conditions. Specifically, existing § 250.451(h) requires that subsea BOP systems used in an ice-scour area must be installed in a well cellar that is deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

Regarding the commenter's recommendation to include sections 13.9.6 through 13.9.8, and section 15, existing § 250.417(c) addresses drilling operations in frontier areas and includes provisions for a contingency plan to include design and operating limitations of the drilling unit where the operator must identify the actions necessary to maintain safety and prevent damage to the environment. Additionally, under existing § 250.418(f), for drilling operations in areas subject to subfreezing conditions, operators are required to include in their APD evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions. Accordingly, BSEE believes that the combination of this rule and existing regulations adequately addresses the commenter's concerns.

One commenter generally agreed with the use of API RP 2N Third Edition, but proposed BSEE also require the operator to document its overall winterization philosophy, as well as specific winterization requirements for MODU drilling systems and equipment.

BSEE disagrees with the commenter's proposal, as the concerns are already addressed in existing rules and with this rulemaking. Although it is not entirely clear what the commenter means by ''overall winterization philosophy'', existing SEMS requirements at §§ 250.1901 through 250.1933 require the operator to have a SEMS program in place that identifies, addresses and manages safety, environmental hazards and impacts during all phases of drilling operations. Additionally, the finalized revisions to § 250.1920 require an annual SEMS audit for exploratory drilling operations on the Arctic OCS. Regarding specific winterization requirements for MODU drilling system and equipment, BSEE has determined the finalized provisions at § 250.473, which requires operators to ensure that equipment and materials are rated or de-rated for service under conditions that can reasonably be expected during operations, and also utilize measures to address human factors associated with weather conditions that can be reasonably expected while operating on the Arctic OCS, ensure that these issues are adequately addressed.

One commenter suggests that the requirements to comply with API RP 2N Third Edition be replaced with a requirement to meet relevant and applicable class rules from a classification society accepted by the IACS. The commenter also suggests that BSEE replace the requirement for the MODU to meet Ice Class 3 standards with a requirement that the MODU be suitably classed to perform expected activities in the area of operations and the seasonal conditions that are expected to be encountered.

BSEE disagrees. API RP 2N Third Edition specifically addresses oil and gas activities in the Arctic and, although IACS has relevant and applicable class rules, we have determined the incorporation by reference of applicable provisions of RP 2N Third Edition is appropriate. BSEE recognizes that, when applied to MODUs, many of the structural criteria of API RP 2N Third Edition are regulated by the USCG and may be covered by Class requirements for marine structures. Classification is a determination made by private organizations that a vessel has been constructed and maintained in compliance with industry standards to be fit for a particular service.

Regarding the commenter's concern that the MODU be required to meet Ice Class 3 standards, we note that although the preamble to the NPRM did mention Ice Class 3 (*see* 80 FR at 9938) we did not propose a regulatory requirement for MODUs to meet specific ice class requirements. BSEE recognizes that MODUs are designed for a specific set of criteria or are classed for a specific environment, water depth, and drilling capacity which, in combination, establishes the design limits of the MODU. MODUs have not traditionally been designed and/or classed specifically for the environmental conditions found in the Arctic region. It is therefore necessary, if MODUs are to be considered for exploratory drilling on the Arctic OCS, to have in place criteria for the assessment of the site and the MODU for the uniquely challenging operating conditions. API RP 2N Third Edition is the current industry standard that provides the criteria for site and MODU assessment. Even if the MODU is reclassified or redesigned for Arctic conditions, operators will still need to perform an assessment for the specific anticipated environmental conditions during the planned window of operations of the MODU on the Arctic OCS, in compliance with the finalized APD requirements of § 250.470. Equipment on the MODU used to support the drilling operations should also be evaluated for suitability for Arctic conditions, but should be evaluated using the appropriate standards for equipment operating in the Arctic environment, not a structural design standard for the Arctic region. BSEE has determined that its selected approach is preferable to both of the alternatives proposed by the commenter.

One commenter stated that BSEE should honor Clause 1 of API RP 2N Third Edition, which provides that this RP does not apply to MODUs. The commenter cautions that the current approach of § 250.470(g), even with exemptions, requires use of API RP 2N Third Edition in situations for which it was not intended.

BSEE disagrees with the commenter's interpretation of the applicability of API RP 2N Third Edition. While the commenter is correct that API RP 2N Third Edition does not apply specifically to MODUs, the procedures relating to ice actions and ice management contained in the standards are applicable to the assessment of such units. Additionally, API RP 2N Third Edition does not specifically preclude the application of appropriate provisions of the document to MODUs. Accordingly, § 250.470(g) calls upon the operator to provide a description of how it will utilize the best practices set forth in API RP 2N. Within that structure, operators have the inherent ability to address the inapplicability of any particular provisions to their operations.

What are the requirements for Arctic OCS source control and containment? (§ 250.471)

The finalized requirements at § 250.471 are designed to ensure that each operator using a MODU and conducting exploratory drilling on the Arctic OCS will have access to, and can promptly and effectively deploy and operate, surface and subsea control and containment equipment in the event of a loss of well control. In particular, BSEE is requiring that each operator have the ability, in the event of a loss of well control, to cap the well and to capture, contain, and process or

properly dispose of any fluids escaping from the well. All SCCE must be mobilized (*i.e.,* begin transit) to the well immediately upon a loss of well control. The rule specifically provides that the SCCE is only necessary when drilling below or working below the surface casing.

Several comments were received on this section. As discussed in Section IV.A, *Summary of Key Changes from the NPRM,* BSEE is revising § 250.471(a) to clearly state that the operator must have access to SCCE equipment capable of ''stopping or capturing the flow of an out-of-control well''. We are also adding paragraph (i) of § 250.471 to clarify when an operator is requesting approval of alternate compliance measures to the SCCE requirements under the provisions of § 250.141, the operator will need to demonstrate that the proposed alternate compliance measure provides a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate compliance measure will be capable of stopping or capturing the flow of an out-of-control well. These revisions are in response to commenters' concerns that the language as originally proposed did not clearly state a performance standard. All other provisions of § 250.471 are finalized as proposed.

Several commenters generally support the provisions. One commenter strongly supported the finalized requirements of § 250.471, but noted for the deployment of technologies such as a capping stack, cap and flow system and a containment dome, there are significant ''response gaps'': Periods in which a particular response tactic could be expected to be ineffective or impossible to deploy based on historic environmental conditions. In a study funded by BSEE, it was found that dispersants, in-situ burning, and mechanical recovery were viable options on the Arctic OCS only 82 percent, 66 percent, and 57 percent of the time, respectively, even during the summer months. During the winter months, the only viable option would be in-situ burning. The commenter argued that, since oil spill response methods are either only sporadically available or not proven to be reliable in Arctic conditions, emphasizing and requiring source control and containment is absolutely critical.

BSEE agrees that effective source control and subsea containment equipment is a critical response capability on the Arctic OCS. Oil spill response countermeasures used to mitigate spills on the surface of the water are always subject to limitations that may arise due to adverse weather and poor on-scene operating conditions. These concerns are heightened under Arctic OCS conditions. The best way to minimize the effects of spilled oil is to prevent it from entering the water in the first place, which is why BSEE agrees that prompt access to SCCE is a critical part in reducing the impacts of a spill and is requiring such equipment and capabilities in § 250.471.

Several commenters recommend that the detailed requirements for source control and containment be removed from the regulations and replaced with performance-based requirements. One of the commenters cautions that requiring specific types of equipment to respond to a loss of well control incident is ineffective and inefficient since it is based upon the false assumption that a loss of well control incident in the shallow waters of the Beaufort and Chukchi Seas would be the same as a deep water well blowout in the Gulf of Mexico. Another of the commenters specifically suggests that the regulations should allow for a specific type of response to a loss of well control — the diversion of wellbore fluids to a flare buoy surrounded by containment boom located a safe distance from other vessels.

BSEE recognizes that operators need to have some flexibility to select the technology that is best suited to planned operations and that alternative technologies may be developed that offer equal or more protection to personnel and the environment than existing technology. We believe the technologies identified in this provision represent the optimal approach to well control capabilities available for the Arctic OCS. However, BSEE acknowledges that it cannot always predict technological developments made by industry. Therefore, we have revised the proposed language at § 250.471(a) to clarify the performance standard required by this provision: That the operator must have access to SCCE that is capable of stopping or capturing the flow of an out-of-control well. Additionally, as discussed in Sections III.D and IV.A, we have added a paragraph (i) of § 250.471 to clearly state that, when an operator is requesting approval of alternate procedures or equipment to the SCCE requirements under the provisions of § 250.141, the operator must demonstrate that the proposed alternate procedures or equipment provides a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well.

In addition, with respect to the ability of operators to utilize alternative technology or procedures, BSEE notes these regulations are intended to ensure that operators have a coordinated and redundant system to provide for adequate safety in exploratory drilling operations on the Arctic OCS. Section 250.471 as finalized contemplates a sequential process based on operator proposals for dealing with Arctic challenges in a risked based manner. In the event of a well control event and failure of the BOP, the first option is to deploy a capping stack. The capping stack is the most immediately deployable equipment of the SCCE options. If the capping stack is not successful, the cap and flow system is the next option. If these options are not deployable, or fail to stop the flow, the containment dome system must be deployed to control the flow during the time it takes the well to bridge off or the relief well to be drilled. Each of these options has a high probability of success, but none is guaranteed to be deployable or successful in all situations. BSEE determined that the finalized provisions provide for the necessary redundancy and sequencing of the responses, based on the time necessary to deploy, and therefore provide sufficient safety and environmental protection to allow for exploratory drilling on the Arctic OCS.

One commenter asserted that the OPA already confers oil spill preparedness and response authority to the operator, USCG and EPA, as well as BSEE through the subject Act and E.O. The commenter cautions that introducing an additional and redundant layer of regulation by BSEE has the potential to lead to confusion and administrative conflicts.

We disagree. BSEE has authority to implement the SCCE requirements under OCSLA. BSEE further disagrees that the finalized requirements of § 250.471 add a redundant layer of regulation that will lead to administrative conflicts. The regulation's focus on equipment related to well control and containment (*i.e.,* preventing release of oil into the environment) complements, rather than conflicts with, the focus on spill response (*i.e.,* cleaning up oil that has been released into the environment) and planning under BSEE's OPA regulations, creating a comprehensive and holistic approach to the relevant issues.

Under OCSLA, BSEE is responsible for implementing environmental safeguards to ensure that oil and gas

exploration and production activities on the OCS are conducted in a manner which minimizes damage to the environment and dangers to life or health, provides for the conservation of the natural resources of the OCS, and will not be unduly harmful to aquatic life in the area, result in pollution, create hazardous or unsafe conditions, or unreasonably interfere with other uses of the area.[34] These regulations allow BSEE to fulfill this obligation by requiring equipment that is fundamental to safe and responsible operations on the Arctic OCS. In that environment, existing infrastructure is sparse, the geography and logistics of bringing equipment and resources into the region is challenging, and the time available to mount response operations is limited by changing weather and ice conditions, particularly at the end of the drilling season. BSEE's OCSLA regulations in Part 250 have long addressed issues surrounding source control equipment and capabilities (see, *e.g.,* §§ 250.401, 250.440 through 250.451, 250.515 through 250.517). BSEE has determined that the SCCE requirements of § 250.471 are necessary and appropriate to account for Arctic OCS conditions and fall squarely within its authority under OCSLA.

These SCCE regulations are needed because exploratory drilling operations on the Arctic OCS are distinct from operations on any other part of the OCS. The logistics and transit times necessary to bring critical equipment to bear in the event of a loss of well control, require the operator to plan for and be prepared for contingencies that would be more straightforward to address in other areas of the OCS. Moreover, there is a limited ability in the Arctic region to summon additional source control and containment resources. Accordingly, operators working there must plan for complexities not confronted elsewhere. At some level, redundancy of equipment response options is both appropriate and necessary in this context, where the redundancies that exist as a matter of course in an environment like the Gulf of Mexico are not present. Rather than adding a redundant layer of regulation, these requirements are specifically geared towards the necessities of operating in this uniquely challenging and fragile environment.

Finally, when writing the rule, BSEE consulted with a number of agencies, including the USCG and the EPA. Moreover, Federal agencies communicate on a regular basis about issues over which they have intersecting authority. Thus, once this rule is in place, BSEE will continue to communicate with other agencies to maximize efficiencies and minimize or eliminate potential conflicts.

Two commenters noted the importance of setting limits on the continued drilling of any well relying on a particular SCCE if a blowout occurs in connection with another operation relying on the same SCCE as a result of mutual aid agreements or cooperatives formed to share SCCE. The commenters note that similar mutual aid agreements and cooperatives have already been formed by Arctic operators to share spill response resources, well capping equipment, and facilities. The commenter provides the example that, if four wells are being drilled and all four rely on the same SCCE package, if one well has a blowout then the other three wells should be suspended and safely secured while the SCCE is committed to the blowout response.

BSEE agrees with the commenter and concludes that this issue is addressed in the performance standard finalized at § 250.471(a), as incorporated into the operator's approved EP (§ 550.220(c)(3)) and APD (§ 250.470(f)). An operator is required to have access to the appropriate SCCE positioned to ensure it will arrive at the well location within a prescribed time limit. This may necessitate halting continued drilling at other well locations if the equipment is being used at the site of the spill in a manner that would preclude the equipment from being accessible for use in a potential well control event at the other well location within the prescribed time limits.

One commenter suggests the final rule should adequately describe technical findings or actual application success rates of containment dome systems used in OCS waters of less than 300 feet, which is commonly found in Alaska's near shore and OCS waters. The commenter questioned whether containment domes have ever safely been deployed in shallow water under a jack-up rig, where leg placement may present hazards when setting the containment dome.

BSEE notes that there has been no need to deploy a containment dome since the Macondo Well blowout in April of 2010.[35] Containment domes have been proposed for Arctic shallow water operations and have been successfully deployed and function tested on multiple occasions. A containment dome is intended to minimize or eliminate the release of oil to the environment in the event that the capping stack or the cap and flow system does not stop an uncontrolled flow. The use of a containment dome is the only tool proposed by an operator to date that has been shown to contain the flow of a well until the well bridges off or the relief well is finished and the well is plugged. BSEE again notes the revision to § 250.471(i) clarifying the performance standard an operator may show for approval of alternative procedures. BSEE may approve innovative methods to contain the flow of oil, in the event that a capping stack, cap and flow system, containment dome or other method of subsea intervention has failed to stop an uncontrolled flow (because of damage to the wellhead, equipment failure, or some other reason), until the relief well can be completed. This performance-based equivalency allows BSEE the flexibility to evaluate well control and containment equipment and devices that may be developed and deployed in the future.

One commenter suggests that BSEE remove the statement indicating that BSEE will direct any emergency response operations, reasoning that it fails to consider interfaces with the current role of the USCG.

BSEE disagrees with removing this statement. As previously described, OCSLA requires that BSEE ensure that OCS oil and gas operations minimize damage to the environment and conserve the natural resources of the OCS. Under OCSLA, BSEE also ensures that OCS oil and gas operations do not result in pollution, create hazardous or unsafe conditions, or unreasonably interfere with other uses of the area.

The deployment of SCCE is a well control measure designed to maintain, or regain, control over a subsea well. The deployment of SCCE will permit an operator to ensure the integrity of an OCS wellbore and maintain control over well pressure and well fluids. For example, a timely deployed capping stack will prevent the release of fluids into the environment in the cap and flow mode. Maintaining or regaining this type of well control ultimately promotes OCS safety, protects the environment, and conserves the natural resources of the OCS. Thus, these regulations implement OCSLA's authorization for BSEE to prescribe regulations concerning oil and gas operations on the OCS.

[34] See, *e.g.,* 43 U.S.C. 1332(3), 1332(6), 1334(a), 1340(g), 1348(b).

[35] After the blowout at the Macondo well on April 20, 2010, the out-of-control well flowed for 87 days until a capping stack was installed on July 12, 2010. On July 15, 2010, it was determined that the flow from the well had stopped. Permanently killing the well required the drilling of a relief well, which was completed on September 16, 2010.

In addition to this OCSLA authority, the President delegated to the Secretary the OPA authority under CWA Section 311(j)(1)(C) concerning ''establishing procedures, methods, and equipment and other requirements for equipment to prevent and to contain discharges of oil and hazardous substances from . . . offshore facilities, including associated pipelines . . . .'' [36] These regulations, including those regarding SCCE, implement the Secretary's OPA authority with respect to equipment, procedures, and methods that prevent and contain oil discharges from offshore facilities.

BSEE's process for interfacing with the USCG with respect to directing well control measures from offshore facilities during a well control event is clearly described and has been carefully coordinated in BSEE/USCG MOA: OCS–03, *Oil Discharge Planning, Preparedness, and Response* (April 3, 2012). MOA: OCS–03 states ''the Regional Supervisor or designated individual will direct measures to abate (stop and/or minimize) sources of pollution from BSEE-regulated offshore facilities to ensure minimal release of oil and to prevent unwarranted shutdown of unaffected production and pipeline systems. However, if an oil discharge poses a serious threat to public health, welfare, or the environment, in accordance with [OPA], the Federal on Scene Coordinator (FOSC) may take action for effective and immediate removal of a discharge and to ensure mitigation or prevention of a substantial threat of a discharge of oil.'' The description of this inter-agency process is ultimately consistent with the National Oil and Hazardous Substances Pollution Contingency Plan's (NCP) requirement that ''[r]esponse actions to remove discharges originating from operations conducted subject to [OCSLA] [must] be in accordance with the NCP.'' [37] It is also consistent with the NCP that vests in the EPA or USCG On-Scene Coordinator the authority to direct all spill response actions. (40 CFR 300.135). Notwithstanding the NCP's clear establishment of OSC authority with respect to directing spill response actions, OPA and the NCP do not generally preempt all other relevant legal authorities. As EPA explained in 1994: ''Section 311(c)(1) of the CWA, as amended by the OPA, gives the OSC authority to 'direct or monitor all Federal, State, and private actions to remove a discharge.' . . . Congress explicitly provided for limited preemption only for contracting and employment laws and this limited preemption applies only when a discharge poses a substantial threat to the public health or welfare of the U.S. There is no express indication that Congress intended to preempt all Federal and State requirements with respect to other discharges.'' [38] BSEE's authority concerning SCCE is consistent with the complementary nature of the NCP in that the OSC has the authority to direct and monitor spill response actions while not preempting all other relevant legal authorities.

One commenter recommended the final rule include a provision requiring the operator to submit an SCCE Emergency Plan as part of the part 550 EP, subject to the public review requirements. The commenter suggests that the SCCE Emergency Plan should include various information, including: The technical and operating specifications of the equipment; standard operating procedures and schedules for testing, operation, inspection, maintenance and repair; and plans for storage, transportation to the well, and deployment. The commenter asserted that written plans provide consistent standard operating procedures for company staff that change over time, provide an excellent reference during an emergency response, and serve as an excellent training tool.

BOEM and BSEE agree with the commenter on the importance of awareness of SCCE assets and response capabilities and planning for their maintenance, deployment, and use. However we do not agree with the need for a specialized SCCE Emergency Plan as part of an operator's EP. Paragraphs (a) and (c) of § 550.220 already require that an operator's EP describe their emergency plans to respond to a fire, explosion, personnel evacuation, or loss of well control, among other things, as well as provide a general description of the operator's SCCE capabilities. The finalized provisions of §§ 250.471 and 250.470(f) also provide for sufficient BSEE oversight of the operator's SCCE capabilities to account for any staff changes over time, including requirements for the operator to: Detail the SCCE and the contractor's SCCE capabilities, include descriptions of all SCCE, and describe procedures for inspection/testing of SCCE.

Paragraph (a), Drilling Below or Working Below the Surface Casing

Paragraph (a) requires that the operator, when using a MODU to drill below or work below the surface casing, have access to a capping stack positioned to arrive at the well within 24 hours after a loss of well control, and a cap and flow system and a containment dome positioned to arrive at the well within 7 days after a loss of well control.

Several commenters recommend that the cap-and-flow system and containment dome should be required to arrive within three days, as the quicker the cap-and-flow system and containment dome are available and on-site, the faster any blowout may be controlled.

BSEE appreciates the commenters' concern for rapid deployment of the cap-and-flow system and containment dome as a means to control any blowout as quickly as possible, and encourages operators to deploy source control and containment assets without undue delay. However, BSEE has decided to finalize this provision with the 7-day timeframe for arrival after the loss of well control. The 7-day timeframe allows for the appropriate arrival of all the SCCE response equipment and responders and facilitates a staged response during the early hours of an event. The cap-and-flow system and containment dome are elements of a systematic approach to the SCCE deployment, and the 7-day requirement provides for the arrival of the system after the operator has had time to deploy and test the capping stack and to complete other more immediate intervention options.

Several commenters recommend BSEE not impose timeframes for the deployment of SCCE and instead allow for performance-based requirements using a risk-based approach. One commenter suggests that the positioning of SCCE assets be determined on a case-by-case basis that takes into account any unique aspects of an operator's program and the well site, and that these tailored mobilization and operational timelines would be best captured in an operator's EP. Another of the commenters specifically urges consideration of the merits of a bottom-founded rig with a pre-installed capping device, which can cap a well in a matter of minutes or hours.

We note the final rule does not prohibit the use of pre-positioned capping stacks when operating a jack-up rig. To clarify this, we have added text to explicitly add a pre-positioned capping stack to the definition of

[36] Executive Order 12777, sec. 2(b)(3), 56 FR 54757 (Oct. 18, 1991).

[37] 40 CFR 300.125(e).

[38] 1994 final revisions to NCP, 59 FR 47389–90 (Sept. 15, 1994).

''Capping Stack'' in § 250.105. We also note that § 550.220(c)(3) does contemplate a description of the operator's SCCE capabilities and plans for compliance in the EP.

In response to commenters' request for a revised timeframe determined either by the use of a pre-positioned capping stack or on a case-by-case basis, BSEE has determined the requirements of this section appropriately implement a coordinated redundant system to provide adequate safety, and declines to modify the rule as suggested. The timeframes implemented in § 250.471 establish a sequential process based on operator proposals for dealing with Arctic challenges in a risk-based manner. In the event of a well control incident, the first option is to deploy a capping stack. The capping stack is the most immediately deployable of the SCCE options. If the capping stack is not successful, the cap and flow system is the next option. If these options are not deployable, or fail to stop the flow, the containment system must be deployed to contain the flow from the well during the time it takes the well to bridge off or the relief well to be drilled. Each of these options has a high probability of success, but none is guaranteed to be deployable or successful in all situations. The redundancy and sequencing of the responses, based on the time necessary to deploy and the increasing complexity, provides sufficient safety in a reasonable and appropriate framework. The 7-day timeframe for deployment of SCCE is the maximum timeframe allowed and, if an operator can deploy appropriate equipment in under 7 days, that is permissible and encouraged to the extent it may enhance the response. If an operator determines alternate procedures or equipment will provide for equal or better levels of protection, as discussed earlier, an operator may submit a request under existing § 250.141, and such procedures may be approved on a case-by-case basis.

Several commenters oppose the specific requirement for timely access to a containment dome, asserting that a performance-based requirement would be more appropriate. Commenters assert that a containment dome poses serious problems and risks in shallow water, and may only be compatible with a narrow range of drilling approaches. One commenter argued that future and existing technologies, including subsea shut-in devices, are being pursued to provide better outcomes in the highly unlikely event of a well control incident in Arctic conditions, and that there is no sound technical basis for including a containment dome as a specific requirement.

BSEE disagrees. The containment dome is intended to immediately contain oil that would otherwise be discharged into the environment in the event that the capping stack or any other method of subsea intervention does not stop an uncontrolled flow. The use of a containment dome is the only tool proposed by an operator to date that has been shown to contain the flow of a well following failure of such control interventions until the well bridges off or the relief well is finished and the well is plugged. As described above, § 250.141 and this final rule at § 250.471(i) allows for the District Manager or Regional Supervisor to approve the use of alternate procedures or equipment provided the operator can show the technology will meet or exceed the level of safety and environmental protection provided by the containment dome. The rule, therefore, specifically provides that BSEE may approve innovative methods to contain the flow of oil, in the event that a capping stack or other method of subsea intervention has failed to stop an uncontrolled flow (because of damage to the wellhead, equipment failure, or some other reason), until the relief well can be completed. This performance-based equivalency allows BSEE the flexibility to evaluate well control and containment equipment and devices that may be developed and deployed in the future.

One commenter requested that, if BSEE does not eliminate the containment dome requirement entirely, the regulations should specify that, when a jack-up rig is used with a subsurface BOP and a prepositioned capping device, a containment dome is not required. The commenter also asserted that the use of a well design using full pressure containment in the wellbore addresses and minimizes the risk of ''broaching'' (the escape of hydrocarbons through the cement occupying the space between the wellbore and the strata outside the casing) precluding the need for any kind of additional well containment, such as a cap and flow system. The commenter asserted that the combination of a jack-up rig, a prepositioned capping device, and a Level 1 well design materially strengthens spill prevention by adapting proven technologies to the Arctic context, and results in unique advantages with respect to spill prevention such as full pressure containment to the rig floor, access to a surface BOP, and a preinstalled cap with a response time of mere minutes.

BSEE disagrees with removing the requirement for a containment dome. Although the commenter refers to a ''prepositioned capping device'', we assume the reference is to a prepositioned capping stack. As discussed previously in this Section, the SCCE requirements are intended to ensure that operators have a coordinated and redundant system to provide for adequate safety in exploratory drilling operations on the Arctic OCS. The capping stack must be positioned to arrive at the well location within 24 hours after loss of well control. If the out-of-control well is not successfully stopped by the capping stack, the other SCCE must arrive at the well location within 7 days after a loss of well control or as directed by the Regional Supervisor. The containment dome is intended to immediately contain oil that would otherwise be discharged into the environment in the event that the capping stack or any other method of subsea intervention does not stop an uncontrolled flow. The containment dome and cap and flow system are part of a sequential process based on operator proposals for dealing with Arctic challenges in a risked based manner. Therefore, removing the containment dome from the sequential approach would negate the intent of the requirements.

Regarding the commenter's suggestion of utilizing a pre-positioned capping stack, we do agree this may be appropriate in specific situations. BSEE notes that this final rule does not preclude the use of a prepositioned capping stack as a part of an operator's proposal. To clarify this, we have revised the definition of Capping Stack to specifically include pre-positioned capping stacks, which may be utilized below subsea BOPs when deemed technically and operationally appropriate, such as when using a jack-up rig with surface trees.

One commenter asserted that the safety and technical issues presented by installing a containment dome between the legs of a bottom-founded rig are sufficient to dismiss the use of a containment dome out of hand in most situations.

BSEE disagrees. This comment assumes that the rig will not have been moved off the location in the event of a loss of well control that has continued for the amount of time it would take to deploy a containment dome (up to seven days under this rule). If the well control event requires that the rig move off location, the containment dome would not only be viable, but necessary to contain the flow during relief well operations. When one considers that the

drilling floor on modern jack-ups is cantilevered off one side of the rig, the premise that the containment system must operate ''between the legs'' also does not follow. Additionally, as discussed earlier, an operator may request to use alternate procedures or equipment under existing § 250.141 and this final rule at § 250.471(i).

Paragraph (b), Stump Test

Paragraph (b) requires monthly stump tests of dry-stored capping stacks, and stump tests prior to installation for pre-positioned capping stacks. The finalized provision imposes a requirement that any capping stack that is dry stored must be stump tested (function and pressure tested to prescribed minimum and maximum pressures on the deck in a stand or stump where it could be visually observed) monthly. The final rule also requires that pre-positioned capping stacks be tested prior to each installation on a well to assure BSEE that no damage was done during the prior deployment or transit.

One commenter recommended that any testing requirements of capping stacks and similar equipment not add to testing requirements in other OCS regions. The commenter asserted that there is no rationale to change these standards for Arctic conditions, and instead suggests revisions to allow for the operator to demonstrate that the SCCE (including elastomers and hydraulic control fluid) are suitable for the expected specific operating environment, including both surface and subsea conditions.

Although it is unclear from the comment what ''similar equipment'' testing requirements the commenter is referencing, BSEE disagrees with the recommendation to align stump testing requirements for Arctic OCS capping stacks with those applicable to other OCS regions. The harsh conditions on the Arctic OCS do justify enhanced regulatory requirements for testing and maintaining equipment, and therefore BSEE has determined that more rigorous stump testing of capping stacks is appropriate. BSEE agrees with the commenter that requirements should be in place to ensure an operator can demonstrate that the SCCE is suitable for the expected operating environment. Accordingly, multiple provisions finalized in this rulemaking require such a demonstration. See, *e.g.,* § 250.473(a) (establishing the requirement that equipment and materials (including elastomers and fluids) to be rated or de-rated for service under conditions that can be reasonably expected during operations); § 250.470(a)(2) (requiring a detailed description of how equipment will be prepared for service in the relevant conditions); § 250.470(f) (requiring a detailed description of SCCE capabilities under Arctic OCS conditions); § 550.220(c) (requiring descriptions in the EP of the suitability of an operator's planned activities and capabilities for Arctic OCS conditions).

Paragraph (c), Reevaluating SCCE for Well Design Changes

Paragraph (c) requires a reevaluation of the SCCE capabilities if the well design changes because some well design changes may impact the WCD rate. If the operator proposes a change to a well design that impacts the WCD rate, the operator must provide the new WCD rate through an Application for Permit to Modify (APM), as required by existing § 250.465(a). The operator must then verify that the SCCE would either be modified to address the new rate or that the previously proposed system would be adequate to handle the new WCD to demonstrate ongoing compliance with the SCCE capability requirements previously addressed.

No comments were received on the proposed addition of this section and the section is therefore finalized as proposed.

Paragraph (d), SCCE Tests or Exercises

Paragraph (d) requires the operator to conduct tests or exercises of the SCCE, including deployment of the SCCE, when directed by the Regional Supervisor. Similar to the requirement that equipment be tested periodically, BSEE has concluded that there is a need to ensure that personnel are prepared and that they, and the SCCE, would be capable of performing as intended. Therefore, BSEE is requiring that operators conduct tests and exercises (including deployment), at the direction of the Regional Supervisor, to verify the functionality of the systems and the training of the personnel.

Three commenters requested § 250.471(d) establish minimum testing requirements and that BSEE provide more specific details as to the timing and number of tests and exercises. The commenters recommend that SCCE be tested prior to each drilling season to ensure it is functioning properly and capable of working effectively during an emergency, and that the equipment be exercised at least once during the drilling season to ensure personnel have the opportunity to practice deployment and use of this critical well control equipment in Arctic conditions. One of the commenters recommended testing or exercises be conducted prior to active operations at a scheduled time so that required trained personnel can participate, and to enable adequate planning. The commenter suggests that, to ensure all required resources will be available at the agreed time, the date for any tests or exercises should be agreed to a minimum of 180 days in advance.

BSEE disagrees with requiring a prescribed frequency of testing of SCCE equipment or with pre-arranging all tests well in advance. The testing requirements in this final rule are the result of balancing logistics and safety concerns against the need to maintain the relevant systems in a constant state of readiness. Placing strictly pre-defined parameters on testing would allow for a level of staging and preparation that is not realistically reflective of the real-world scenarios in which the relevant capabilities would be needed. The Regional Supervisor should be allowed to determine the appropriate balance on a case-by-case basis. The SCCE equipment is not directly involved in drilling and, as such, the required state of readiness and availability can only be attained by testing as proposed, which allows for a case-by-case flexibility.

One commenter recommended testing the SCCE in Arctic OCS conditions at the exploration drill site during the drilling season.

BSEE has determined the logistics of testing at the Arctic OCS site introduce more risk than such testing would alleviate. One example of the types of difficulties of onsite testing in Arctic OCS conditions is that it is currently not feasible to transport to the Arctic the large volume of nitrogen that is required for recharging equipment. Nitrogen recharging of the surface SCCE equipment is used to help control corrosion during deployment and also helps minimize the risk of explosion, should use of the equipment become necessary. Recharging the system also helps monitor the system for leaks. Because recharging cannot currently be accomplished onsite, in the Arctic, it is more prudent to conduct testing and accomplish recharging outside the Arctic, where the nitrogen charges can be transported. This approach helps to ensure that the SCEE equipment will be properly charged and will be capable in the unlikely event that it is needed to response to a well control event during operations.

Paragraphs (e) and (f), SCCE Records Maintenance

Paragraph (e) requires the operator to maintain records pertaining to testing, inspection, and maintenance of the SCCE for at least 10 years, and make them available to BSEE upon request. This information will facilitate a review

of the effectiveness of the operator's inspection and maintenance procedures and provide a basis of review for performance during any drill, test, or necessary deployment. A 10-year record retention requirement is necessary to ensure enough cumulative data is gathered to assess overall equipment performance and trends.

Paragraph (f) requires the operator to maintain records pertaining to use of the SCCE during testing, training, and deployment activities for at least 3 years and make them available to BSEE upon request. The use of the equipment during testing and training activities and actual operations must be recorded, along with any deficiencies or failures. These records will allow BSEE to address any issues arising during the usage and to document any trends or time-dependent problems that would develop over the record retention period. In the event that the equipment is used in a well control incident, the records are necessary to document the effectiveness of the response and functioning of the equipment.

Two commenters recommend that all records be retained for a consistent period and electronically submitted to BSEE, unless BSEE can explain the reason for recommending a different record retention schedule.

BSEE disagrees. The record maintenance requirements are intended to mirror current regulations to the extent possible given the long lead times and down periods in Arctic exploratory drilling. *See* §§ 250.426, 250.434, 250.450 and 250.467. BSEE has determined electronic submission should remain an option, not a requirement.

Paragraphs (g) and (h), Mobilizing and Deploying SCCE

Paragraph (g) requires operators to initiate transit of SCCE to a well immediately upon a loss of well control. Paragraph (h) requires that operators deploy and use SCCE when directed to do so by the Regional Supervisor. This provision ensures that all SCCE is available and ready for use and reinforces the Regional Supervisor's authority and discretion to require the deployment and use of SCCE in the event of a loss of well control.

One commenter suggests revising these sections to indicate that the Regional Supervisor must consult with the FOSC (and State on Scene Coordinator (SOSC) in state waters, and appropriate stakeholders and technical experts regarding the deployment of SCCE. The commenter expressed concern that the proposed requirements of § 250.471(h) indicate that the Regional Supervisor has the full authority to require the deployment of the capping stack and cap and flow system, without any requirement to consult with the Regional Response Team, the FOSC, or any technical experts. The commenter asserted that, under Federal law, the FOSC is in charge of oil spill response and is the sole Federal entity authorized to require actions to control a potential discharge. Another commenter further recommended that §§ 250.471(g) and (h), and § 250.472(a) should be eliminated or expressly subordinated to direction from the FOSC through the Incident Command System (ICS). The commenter alternately suggests that, if this recommendation is not accepted, BSEE should revise the provision to clarify that any direction to deploy or use SCCE or a relief rig by the Regional Supervisor must be requested within the Unified Command.

BSEE is aware that through OPA and the NCP, ''[t]he OSC in every case retains the authority to direct the spill response, and must direct responses to spills that pose a substantial threat to the public health or welfare of the United States.'' (59 FR 47384, 47387 (Sept. 15, 2016)). In this context, BSEE will continue to consult with the USCG as the on scene coordinator with the authority to direct and monitor spill response actions under the NCP. Notwithstanding, BSEE recognizes that OPA and the NCP do not expressly preempt all other relevant legal authorities that may be implicated during a spill response. (59 FR 47389–90 (Sept. 15, 1994)). The final rule's requirement that an operator deploy and use SCCE when directed by the Regional Supervisor in § 250.471(h) is consistent with BSEE's OCSLA authorities concerning the regulation of oil and gas exploration activities on the OCS. Neither OPA nor the NCP preempts BSEE's regulatory authority with respect to the regulation of these activities. Additionally, as discussed above, in addition to this OCSLA authority, the President delegated to the Secretary the OPA authority under CWA Section 311(j)(1)(C) concerning ''establishing procedures, methods, and equipment and other requirements for equipment to prevent and to contain discharges of oil and hazardous substances from . . . offshore facilities, including associated pipelines . . .'' These regulations, including those regarding SCCE, implement the Secretary's OPA authority with respect to equipment, procedures, and methods that prevent and contain oil discharges from offshore facilities.

The BSEE Regional Supervisor has both the technical expertise for source control operations and the authority to require the operator to implement SCCE measures under OCSLA. MOA:OCS–03 describes the roles of BSEE and the USCG during responses to spills from offshore facilities: ''In the event of an oil discharge or substantial threat of an oil discharge from an offshore facility seaward of the coastline, BSEE has primary responsibility for monitoring and directing all efforts related to securing the source of the discharge and reestablishing source control . . . the Regional Supervisor or designated individual will direct measures to abate sources of pollution from regulated offshore facilities to ensure minimal release of oil and to prevent unwarranted shutdown of unaffected production and pipeline systems.'' Both BSEE and the USCG acknowledge the need to seamlessly coordinate source control and other oil spill response activities. BSEE and the USCG established the position of the Source Control Support Coordinator (SCSC) within ICS framework and the 2014 edition of the USCG Incident Management Handbook (IMH). As provided for in the USCG IMH, ''the SCSC . . . is the principal advisor to the FOSC for source control issues. The SCSC serves on the FOSC's staff and is responsible for providing source control support for operational decisions and for coordinating on-scene source control activity. During a source control issue involving a loss of well control or pipeline incident on the OCS, the SCSC and other source control technical specialists are provided by BSEE.'' As such, there are clear policies in place and already agreed to between the USCG and BSEE regarding how source control activities resulting from a loss of well control should be implemented and how they should be addressed within ICS and the Unified Command. The provisions within this rulemaking are consistent with all existing statutory authorities, MOA:OCS–03, and the USCG's ICS framework within the IMH.

One commenter recommended that BSEE link the SCCE requirements to the operator's approved Emergency Response Plan such that, in the event of a loss of well control, the primary SCCE will be mobilized in accordance with the operator's approved Emergency Response Plan. The commenter also recommended that, during the transit of the primary SCCE, the operator will administer secondary intervention measures per their response plans to terminate or minimize the flow of hydrocarbon to the seafloor. The

commenter also requested additional clarification of BSEE's level of responsibility, accountability and liability in the event of any incidents that occur as a result of the operator complying with the requirements of § 250.471(g), pursuant to which the operator must deploy and use SCCE when directed by the Regional Supervisor.

This provision is intended to emphasize that the purpose of the SCCE requirement is to ensure that the operator is able to quickly commence source control operations, and BSEE does not agree that the suggested revisions are needed. The timeframes finalized in § 250.471 are minimum planning standards and may become relevant well before the ICS is activated and an Emergency Response Plan comes into play. This is also especially important with respect to the beginning of relief well operations under § 250.472.

Regarding the comment on BSEE's associated responsibility, accountability, and liability if § 250.471 requirements are invoked, BSEE clarifies that we do not propose to assume control over any operations. The finalized provisions of this rulemaking simply require the operator to comply with the terms of the regulations and its approved plans and permits and discuss BSEE's authority to order such compliance. The operator is responsible for safely executing all operations in compliance with the regulations and its approved plans and permits. BSEE has no authority to offer advisory opinions concerning the scope of potential executive agency legal liability. BSEE is authorized to prescribe rules and regulations that are necessary to carry out the provisions of OCSLA. (43 U.S.C. 1334(a)). Questions concerning legal liability are beyond the scope of this rulemaking and BSEE makes no representations concerning legal liability in this rule.

Paragraph (i), Approval of Alternative Compliance Measures

As discussed in Section IV.A, *Summary of Key Changes from the NPRM,* in response to comments BSEE is adding a paragraph (i) to clarify when an operator is requesting approval of alternate compliance measures to the SCCE requirements under the provisions of § 250.141 and this final rule, the operator should demonstrate that the proposed alternate compliance measure provides a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate compliance measure will be capable of stopping or capturing the flow of an out-of-control well. These revisions are in response to commenters' concerns that the language as originally proposed did not clearly state a performance standard.

What are the relief rig requirements for the Arctic OCS? (§ 250.472)

BSEE proposed to add a new § 250.472 which requires an operator to have available a relief rig when drilling below or working below the surface casing. The provisions also proposed to establish a 45-day maximum limit on the time necessary to complete relief well operations. BSEE notes the relief rig could be stored in harbor, staged idle offshore, or actively working, as long as it would be capable of physically and contractually meeting the proposed 45-day maximum timeframe. However, any relief rig must be a separate and distinct rig from the primary drilling rig to account for the possibility that the primary rig could be destroyed or incapacitated during the loss of well control incident.

Many commenters expressed general support for the relief rig requirements. Many other commenters suggested various revisions to this section. As discussed in Section IV.A, *Summary of Key Changes from the NPRM,* BSEE is revising the language of this section in response to comments to clarify the performance standard that must be met when proposing to use alternate equipment or procedures to the relief rig requirements of § 250.472. Specifically, we are adding the phrase ''able to kill and permanently plug an out-of-control well'' to the proposed § 250.472(a) to clearly state the performance standards the relief rig must achieve. We are also revising the proposed § 250.472(c) to clarify when an operator is requesting approval of alternate compliance measures to the relief rig requirements under the provisions of § 250.141 and this final rule, the operator will need to demonstrate that the proposed alternate compliance measure provides a level of safety and environmental protection that meets or exceeds that required by BSEE regulations, including demonstrating that the alternate compliance measure will be able to kill and permanently plug an out-of-control well. These revisions are in response to commenters' requests for a clear statement of a performance standard and are designed to offer guidance and clarification to operators with respect to the performance-based standard established by this rule that any proposed alternate compliance must meet or exceed. All other provisions of § 250.472 are finalized as proposed for the reasons discussed herein.

Several commenters recommended that BSEE remove the relief rig requirements and revise the final regulations to implement a performance-based equipment requirement. Commenters suggest that the availability of several alternative technologies, such as capping stacks, prepositioned capping devices, and subsea isolation devices (SID), negate the need to require a relief rig.

BSEE disagrees with the suggestion to remove the relief rig requirement. We have determined that a relief rig is currently the most reliable option for permanently killing and plugging an out-of-control well. We do agree with the commenters' concerns that the regulations provide flexibility and allow for the use of new technology that can meet or exceed the level of safety and environmental protection provided by a relief rig in the event of an out-of-control well. None of the types of technology proposed by the commenters, however, have been proven to be conclusively, and consistently, effective at killing and permanently plugging an out-of-control well. Therefore, BSEE has determined to finalize the § 250.472 requirement for an operator to have appropriate access to a relief rig, different from the primary drilling rig, when drilling or working below the surface casing during Arctic OCS exploratory drilling operations.

Although a relief well is the most reliable, and in some circumstances the only available, solution to kill and permanently plug an out-of-control well, there may be circumstances where innovative alternative compliance measures to drilling a relief well are available. The proposed § 250.472(c) addressed this concern by directing operators to existing § 250.141, *May I ever use alternative procedures or equipment?.* In response to comments, we have revised § 250.472(a) to include a more explicit performance standard, where the relief rig must be able to ''kill and permanently plug an out-of-control well''. We have also revised the language of proposed § 250.472(c) as set out in the regulatory text at the end of this document.

Many comments also requested additional clarity and explicit procedures for an operator to apply for the use of equivalent technology.

BSEE understands the commenters' stated reasons for desiring additional details about how to obtain approval for alternative procedures or equipment under § 250.141 and this final rule. As discussed in Section III.B and D of this preamble, operators may request

approval for innovative technological advancements that may provide them additional flexibility, provided that the operator can establish that such technology provides at least the same level of protection as the relief rig requirements.

One commenter asserted that the requirement for a relief rig under § 250.472 is in conflict with the preference for performance-based regulations established in E.O. 12866, E.O. 13563 and associated guidance.

BSEE disagrees. Section 250.472 is consistent with the relevant portions of E.O. 12866, E.O. 13563 and the associated Office of Information and Regulatory Affairs (OIRA) guidance because it would allow for operators to utilize less expensive technologies that achieve the performance outcome of permanently killing and plugging an out-of-control well in a timely fashion. Importantly, within certain general parameters, the proposed regulation leaves a fair amount of discretion with the operator as to how to accomplish that outcome. Although this provision presumptively requires that operators have access to relief rigs to achieve the regulatory outcome, it sets forth the minimum level of prescription necessary to achieve the end, leaving many performance-based options available for operators to pursue. Additionally, § 250.472(c) expressly permits operators to propose alternate equipment to achieve the regulatory objective of permanently killing and plugging an out-of-control well. We note that we considered at the NPRM stage imposing more prescriptive requirements for relief rig capabilities, but instead chose to provide operators flexibility by selecting the best approach that would accomplish the ultimate goals.[39]

Many commenters expressed their support for the NPC Arctic Potential Study and suggest we revise the relief well requirements to align with the Study's findings. The commenters cite to the NPC Arctic Potential Study's suggestion of alternative preventative measures such as well design, capping stacks or subsea shutoff devices as methods of spill mitigation and containment.

BSEE disagrees with the recommendation to revise § 250.472 and does not view the requirements finalized in this rulemaking as being in conflict with the NPC Arctic Potential Study. As discussed in Section IV.B.1, *General Comments,* BOEM and BSEE recognize the NPC Arctic Potential Study as a valuable comprehensive study that considers the research and technology opportunities to enable prudent development of U.S. Arctic oil and gas resources. However, it is only one of the resources our regulatory experts considered in developing regulations to ensure the safe and responsible development of petroleum resources on the Arctic OCS. BSEE has determined that the relief rig requirements are appropriate to ensure the operator is able to kill and permanently plug an out-of-control well in a reasonable and safe amount of time. Additionally, the finalized provisions of § 250.472 align with the NPC Arctic Potential Study's recommendations for the availability of alternate technology to a relief rig. We note that operators generally do not view relief wells as the preferred alternative in a well control event. As reflected in § 250.471 and throughout its existing source control regulations, BSEE, too, does not view a relief well as a first-choice well intervention. Although a relief rig is the primary technology for killing and permanently plugging an out-of-control well, it is intended to be a part of the continuum of response, beginning with the source control and containment intervention measures. However, in the Arctic, due to the very short portion of the year in which well locations are accessible, BSEE has determined that timely access to a relief rig is an appropriate requirement to ensure the lowest risk of a prolonged uncontrolled flow under the ice, which will cover the site for a majority of the year. BSEE has not identified an alternative technology that provides the same level of reliability for permanently killing and plugging an out-of-control well following attempts, successful or unsuccessful, to achieve temporary control through more direct intervention options. An operator may always request approval of alternate equipment or procedures under § 250.141 and this final rule, as appropriate. These alternative compliance measures may be approved if they are shown to meet or exceed the level of safety and environmental protection provided by the relief rig requirements of § 250.472.

Two commenters opposed the use of any equipment performance standard in this provision, asserting that the requirement for a relief rig should be mandatory. The commenters assert that permitting the use of any alternative compliance measures would necessitate a formal rulemaking with public notice and comment.

BSEE recognizes the commenters' concern, but disagrees with precluding the use of any alternative procedures or equipment to the relief rig requirements of § 250.472. We note that the ability of industry to innovate within regulatory constraints requires a careful balance, especially when undertaken in environmentally sensitive areas such as the Arctic OCS. In attempting to strike this balance, we have determined the hybrid prescriptive and performance-based requirements of § 250.472 are appropriate. Further, no additional formal rulemaking is necessary because an operator's option to apply for the use of alternate compliance measures is always available for any of the part 250 regulations under the existing regulatory provisions previously promulgated through notice and comment procedures at § 250.141.

Two commenters asserted that the relief well requirement is not best available and safest technology (BAST) as required by OCSLA at 43 U.S.C. 1347(b).[40] One of the commenters asserted that BAST for source control is a capping stack, not a relief well, because drilling a same season relief well takes significantly longer to control a source than does the deployment of a capping stack, and the risk profile associated with drilling a same season relief well is greater than that associated with a capping stack. Several commenters cite two Minerals Management Service (MMS) studies[41] as supporting the assertion that relief rigs are not an effective means to kill and permanently plug an out-of-control well and therefore should not be included in regulatory requirements.

BSEE disagrees with the commenters. We determined that there is adequate support for requiring a relief rig for Arctic OCS exploratory drilling operations. BSEE has concluded that the requirement to have access to and utilize a relief rig to kill and permanently plug an out-of-control well is necessary and appropriate under Arctic OCS conditions. Although the commenters point to the MMS Studies as countering this conclusion, the MMS studies examined blowouts only

[39] 80 FR 9940.

[40] The Secretary of Interior ''shall require, on all new drilling and production operations and whenever practicable, on existing operations, the use of the best available and safest technologies (BAST) 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.''

[41] Izon, David, Danenberger, E.P., and Mayes, Melinda, ''Absence of Fatalities in Blowouts Encouraging in MMS Study of OCS Incidents 1992–2006'', Drilling Contractor magazine, pages 84–90, July/August 2007; Danenberger, E.P., ''Outer Continental Shelf Drilling Blowouts, 1971–1991'', OTC #7248, 25th Annual Offshore Technology Conference, Houston, Texas, May 1993.

occurring on the Gulf of Mexico OCS, with the exception of one on the Pacific OCS. As discussed throughout this final rule, the Arctic OCS is a uniquely challenging operating environment. In the Arctic, exploratory drilling operations from MODUs occur only during the open water season, in a region with little or no infrastructure that is subject to variable and sometimes extreme weather, and where transportation systems could be interrupted for significant periods. Additionally, if a blowout occurs during the open water season, it is imperative to permanently kill and plug the well in as short a time as possible, as ice encroachment may complicate or prevent drilling and transit operations and preclude a resolution of the situation before the extended off-season.

Commenters also appear to misconstrue the nature of the relief rig requirements, particularly their connection with the SCCE requirements of § 250.471. Commenters emphasize the preference for using capping stacks to regain prompt and immediate control of an out-of-control well. BSEE agrees with this assertion, as reflected in the provisions of § 250.471 requiring Arctic OCS operators to have a capping stack stationed nearby for prompt deployment to an out-of-control well as an initial response. BSEE acknowledges the timelines and challenges that accompany relief well operations, particularly on the Arctic OCS. BSEE does not propose the relief rig as an alternative to the capping stack, but rather as a supplement to the capping stack serving the distinct purpose of permanently killing and plugging the well. While capping stacks are sometimes—though not always—capable of regaining immediate control over a well, BSEE believes that the best available option to kill a well reliably and permanently, and to allow for safe longer-term abandonment, is a relief well. Accordingly, a relief rig is not an alternative to a capping stack, but rather a separate line of defense in the event of its failure, and/or the most reliable method for shifting from the temporary control potentially provided by a capping stack to the permanent killing of an out-of-control well on the Arctic OCS. Additionally, as discussed previously, operators may utilize alternate equipment or procedures if they can show the alternate compliance measures meet or exceed the level of safety and environmental protection provided by a relief rig. Specifically, the alternate compliance measure must demonstrate the ability to kill and plug an out-of-control well permanently; separate and distinct from the potential immediate well control capabilities of a capping stack.

BSEE notes that, under § 250.107(c), it presumes that an operator's compliance with BSEE regulations constitutes BAST. BSEE's Office of Offshore Regulatory Programs is responsible for developing and maintaining regulations, policies, standards and guidelines related to BAST. We continuously strive, through programs, such as the Technology Assessment Program, and collaborations, such as the Ocean Energy Safety Institute, to identify and incorporate new and evolving technologies into our regulation of OCS oil and gas activities. The regulations applicable to MODUs conducting exploratory drilling on the Arctic OCS reflect these efforts. The relief rig, SCCE, and other regulations require a coordinated and redundant system to provide for adequate safety in exploratory drilling operations under the uniquely challenging environmental and operational conditions on the Arctic OCS. BSEE has determined the finalized provisions in this rulemaking provide for the appropriate redundancy and sequencing of the responses, based on deployment time and varying equipment capabilities, and therefore provides the necessary level of safety and environmental protection to allow for exploratory drilling on the Arctic OCS.

One commenter further questioned BSEE's support for requiring a relief rig for exploratory drilling operations from a MODU or jack-up on the Arctic OCS, and requested identification of the administrative record. The commenter asserted that BSEE should allow for public comment on the administrative record when it is publicly identified.

Generally defined, an administrative record is a compilation of the body of information considered directly or indirectly by an agency decision-maker in arriving at a final decision. The administrative record is created from the decision record, which is an evolving resource through development of the proposed rule on to promulgation of the final rule. Public comments, including those submitted by the commenter, are part of the administrative record. As it does with all of its proposed rules, BSEE invited public comments on the NPRM and supporting documents and data to ensure that it considers a wide range of environmental, economic, and other issues related to the proposed rule. The commenter submitted this comment during the public comment period of the rulemaking process, and therefore prior to the final agency decision. The administrative record is complete when the Department issues the final rule, not before. In addition, administrative records are not subject to public review and comment requirements under applicable law. We note, however, the public may view the public rulemaking docket at any time. The docket, available at *www.regulations.gov,* contains all public comments, as well as additional documents and information relied upon in the finalization of these regulations. BOEM and BSEE carefully considered all comments on the proposed rule on the requirement for a relief rig—along with a host of other resources that make up the overall administrative record—and, as discussed previously, determined that the requirement for a relief rig is both necessary and appropriate for exploratory drilling operations on the Arctic OCS.

Several commenters oppose the 45-day maximum limit on the time necessary to complete relief well operations and request that BSEE allow for a performance-based requirement to determine the end of drilling season date on a case-by-case basis. Many of the commenters also state the 45-day limit unnecessarily shortens the drilling season on the Arctic OCS, and consequently lessens the value of existing leases.

BOEM and BSEE note the proposed 45-day maximum limit does not seek to impose a specific requirement. The 45-day threshold marks the maximum time allowed, but the requirement is performance-based and leaves the means of compliance up to the operator.

BOEM and BSEE will take a precautionary approach to evaluating proposals to complete relief well operations,[42] particularly those proposing a window of less than 45 days. This evaluation will be part of the review by BOEM in the EP process under § 550.220(c)(4) and BSEE in the APD process under § 250.470(e). BOEM and BSEE will apply a presumption that 45 days is the appropriate amount of time needed to ensure successful completion of relief well operations, including safe transit from the well site. Any proposal by an operator that seeks to demonstrate the ability to complete relief well operations in less than 45 days will be made public by BOEM's posting of the operator's EP once it is deemed submitted. The public will have an opportunity to review and comment

[42] Operators may request approval to use alternative compliance measures that meet or exceed the level of safety and environmental protection in accordance with § 250.472. This evaluation would also apply to any approved alternative compliance measures.

on the EP, including the operator's plans for completing relief well operations in 45 days or less. If an operator seeks to make such a demonstration, BOEM and BSEE will undertake a rigorous, data-driven approach to ensure that sufficient time is allocated for the operator to complete relief well operations. Specifically, BOEM and BSEE will require that the length of the shoulder season encompass the amount of time that is needed to ensure successful relief well operations, taking full account of the cumulative risk of delay across the steps required for completion of relief well operations, including potential delays that may occur due to the following: Weather disruption, the presence of ice that cannot be handled by any available ice breakers and other ice management vessels, equipment or process malfunctions, uncertainties associated with the duration of time required to achieve successful relief well intervention, and any other variables related to relief well operations. Whether the deployment of ice breakers or other ice management vessels is included in the EP will also be evaluated. A reduction below 45 days will be granted only to the extent justified after applying this precautionary approach to assessing plans.

One commenter expressed concern that current technology has not advanced to a point where oil can be effectively cleaned up when mixed with ice, or worse, trapped under the ice.

BSEE understands the commenter's concern, but notes the finalization of this rulemaking specifically limits operations to the open water season and requires early termination of operations when drilling below or working below the surface casing. The early termination is designed not only to allow the drilling of a relief well, but also to enable the use of oil spill response equipment prior to freeze-up. BSEE acknowledges, in certain situations, some cleanup of oil in ice could become necessary, and has required operators to develop oil intervention practices that will enhance the effectiveness of spill countermeasures when dealing with oil in broken ice conditions. Oil spill response techniques do exist for responding to oil spills in Arctic conditions. Research and development designed to improve oil spill response countermeasure technologies and procedures are continuous and ongoing, including efforts that are funded by both government and industry entities.

One commenter generally supported this rulemaking's emphasis on equipment redundancy to contain or control a WCD. The commenter recommended revising this section to encourage operators to demonstrate the success rate of capping operations and equipment, as well as to provide confidence levels of dealing with a number of discharge scenarios.

BSEE disagrees with the recommended revision. As discussed previously, the relief rig requirement is not the primary method of control or containment. The commenter's concern for encouraging redundancy is addressed in § 250.471, which requires Arctic OCS operators to have a capping stack stationed nearby for prompt deployment to an out-of-control well as an initial line of response. BSEE does not propose the relief rig as an alternative to the capping stack, but rather as a supplement to the capping stack, serving the distinct purpose of permanently killing and plugging the well. Regarding opportunities to demonstrate the success rates of capping operations and equipment, § 250.471(b) requires stump testing of capping stacks at specific intervals, and § 250.471(d) directs operators to conduct testing when directed by the BSEE Regional Supervisor. Accordingly, we agree there should be redundant capabilities covering a wide range of scenarios to be employed during an emergency situation, and the finalized provisions of this rulemaking adequately address this issue ensure.

Two commenters requested that, if the 45-day maximum timeframe is finalized, the WCD regulations at § 254.26(d)(l) should be revised to align with the maximum time allowed to drill a relief well, such that the operator must plan for a blowout lasting up to 45 days. Another commenter expressed general concern for how the WCD is calculated.

BSEE has determined the differing timeframes do not necessitate a revision at this time. The 45-day provision is the maximum timeframe allowed for an operator to move the relief rig to the site of the blowout and complete all necessary operations to kill and abandon the original well and abandon the relief well prior to seasonal ice encroachment. Existing regulations in § 254.26 provide a broad performance-based standard requiring plan holders to establish what a WCD would be, and then ensure that enough response and supporting resources are available to clean up such a discharge. Although § 254.26(d)(1) provides the WCD scenario must show how an operator will support operations for a blowout lasting 30 days, it does not preclude developing a scenario lasting longer than 30 days, nor does the hypothetical prospect of a spill lasting longer than 30 days necessitate revision of that regulatory timeline. Accordingly, NTL 2012–N06 *Guidance to Owners and Operators of Offshore Facilities Seaward of the Coast Line Concerning Regional Oil Spill Response Plans,* encourages operators to consider a variety of factors when developing a response strategy for each WCD, including planning to support response to a spill lasting longer than 30 days.[43]

One commenter suggests BSEE adopt a geographic prescriptive standard, requiring operators to maintain a relief rig within a certain distance of their drilling operation. The commenter asserted that the proposed performance-based requirements could still be maintained as a backstop in order to impose liability on any operator that fails to drill a relief well in a timely manner, even while compliant with the prescriptive standards.

BSEE disagrees. As discussed in the preamble to the NPRM, we did consider a prescriptive geographic standard, but based on both 2012 and 2015 operational experience and public comments to the proposed requirements of § 250.472, we determined to retain the 45 day maximum time allowance within a performance-based requirement to provide the operator flexibility to innovate and avoid unanticipated logistical consequences.

One commenter requested that BSEE mandate an additional 10-day buffer period before an operator's established end of season date to allow for unforeseen circumstances. The commenter asserted the additional time added to the end of season date will help mitigate the risk of relief well operations not being completed before the encroachment of winter sea ice and avoid the consequences of a spill continuing until the following open water season.

BSEE has determined it is not necessary to impose a mandatory additional 10 day buffer, because this rulemaking specifically limits operations to the open-water season. The requirement to be able to complete relief well operations prior to the expected encroachment of seasonal ice results in the end of drilling operations well in advance of winter sea ice encroachment and therefore provides an adequate buffer to accommodate the risks of a late season loss of well control. Further, a significant portion of the last 10 days of operations will be spent permanently or temporarily abandoning a well and most of the

[43] Available at *http://www.bsee.gov/Regulations-and-Guidance/Notices-to-Lessees-and-Operators.*

operations occurring at the end of the drilling season will be significantly safer than the drilling itself. Because the regulations already require operators to stop drilling below or working below the surface casing well before the encroaching ice season, BSEE does not believe a mandatory 10-day buffer period is necessary to further mitigate risk.

Two commenters request clarification of how an operator will calculate the expected onset of seasonal ice encroachment when determining the end of seasonal operations to meet the proposed requirements of § 250.472. The commenters express concern that the calculation does not take into account periodic ice incursions during the open water season, and how potential ice management activities, which could include rig movement, interact with this requirement.

BSEE clarifies that the operator will calculate the freeze-up date based on historical data and will update it daily, in conjunction with the daily ice reports, as the season nears its end. Periodic ice incursions occur mostly during the early part of the open water season as the ice breaks off and floats away. Section 250.472 relates to the projected return of seasonal sea ice to the drilling site at the end of the open water season. However, an operator's ice management plan is always in effect with the included ice monitoring provisions.

One commenter asserted that the language of § 250.472(b) prohibiting ''drilling below or working below the surface casing'' during the relief well buffer period conflicts with the proposed provisions at § 550.220(c)(6), requiring ''[t]he termination of drilling operations into zones capable of flowing liquid hydrocarbons to the surface.'' The commenter asserted that, taken literally, an operator could not even conduct operations that are required by regulations during this relief well buffer period. The commenter suggests that, as drafted, the BOEM provision of part 550 references § 250.472 and that the more restrictive BSEE language would prevail if the two sections were reconciled. The commenter requested the conflict between the two provisions be addressed in a re-proposed rule by retaining the language under proposed § 550.220(c)(6), and removing the applicable language of § 250.472(b).

We agree with the commenter in part. The intent of § 550.220(c)(6)(ii) is to obtain the information that is known at the time of EP submission regarding the operator's plans for compliance with the requirements of § 250.472(b). Therefore, as a technical correction, we removed the text of ''into zones capable of flowing liquid hydrocarbons'' from § 550.220(c)(6)(ii) in this final rule. There is no need to re-propose this provision because the intent of § 550.220(c)(6)(ii) was stated as requiring the operator to include in the EP information ''consistent with the relief rig planning requirements under § 250.472'' and this revision does not change the intent of § 550.220(c)(6)(ii) as proposed. We disagree with the commenter's second suggestion that the proposed language of § 550.220(c)(6) should be retained, instead of the finalized language of § 250.472(b), ''drilling below or working below the surface casing.'' Operators may drill or work down to the surface casing at any time. However, the risk of a blowout is increased while working or drilling below that casing, including before drilling into areas expected to be capable of flowing liquid hydrocarbons (such as by way of example, shallow gas pockets). Therefore, the finalized language ''below the surface casing'' ensures that an operator stops at that last casing point, or pulls back and temporarily plugs at that casing point, to meet the requirements of § 250.472(b) and have appropriate capabilities to complete the relief well sufficiently in advance of seasonal ice encroachment.

One commenter suggested the end of seasonal operation dates should not be determined by the operator.

BSEE disagrees. The anticipated end of season date is determined by the operator because they have the primary responsibility to conduct operations in a safe and environmentally responsible manner. They also have the best access to the relevant information related to their equipment and capabilities to operate within certain conditions and timelines (*e.g.,* how long it will take to complete a relief well based on their planned relief rig equipment and staging). Additionally, the operator is in the best position to manage adaptively the extent of operations in the Arctic in light of rapidly changing late-season conditions and in recognition of the extremely short drilling season. BOEM and BSEE provide the regulatory oversight of exploratory drilling operations, however, and any determination of projected end of season dates made by the operator must be reviewed by BOEM and BSEE under the provisions of the EP (§ 550.220(c)(6)) and the APD (§ 250.470(e)). BOEM ultimately approves the end of season date and would need to approve any changes made to the date established in the EP.

One commenter suggests BSEE require relief rigs be in the Arctic OCS area where drilling is underway, to allow the rig to be in place and operating within one week of a blowout occurring.

BSEE agrees with the commenter's concern for a timely response in the event of a blowout occurring. However, BSEE determined the best method of protection is not to prescriptively require an operator to stage a relief rig within a specific geographic area. While BSEE considered imposing such a requirement, we ultimately determined that the performance-based approach of establishing a 45-day maximum, but otherwise permitting the operator to determine its approach to relief rig staging, was preferable. This approach allows the operator flexibility in the management of its rigs while still ensuring that basic safety and environmental protection standards are met. Additionally, the response capabilities finalized in § 250.471 for SCCE will be activated and deployed at the same time that the relief rig is moving into location, mooring up and getting ready to drill, with the initial response required within 24 hours. The relief rig and SCCE requirements are not mutually exclusive operations and can proceed concurrently.

One commenter expressed concern that mutual-aid agreements or cooperatives formed to share relief rigs may inhibit the effectiveness of response. The commenter recommended the final rule set limits on continued drilling of any well relying on a particular relief rig if a blowout occurs and that rig is dedicated to blowout response.

BSEE agrees with the commenter and believes this issue is addressed in the performance standard finalized at § 250.472(b), and incorporated into the operator's approved EP (§ 550.220(c)(4)) and APD (§ 250.470(e)). An operator is required to have access to a relief rig, different from the primary rig, that is able to move onsite to drill a relief well, kill and abandon the original well, and abandon the relief well prior to seasonal ice encroachment at the drill site, but no later than 45 days from a loss of well control. The commenter is concerned with a circumstance in which a single relief rig is relied upon to provide the necessary capabilities for multiple operations (pursuant to a mutual aid or cooperative agreement), and is called into service by a well control event at one of the well sites. Under such circumstances, any other continued drilling operations that rely on the availability of that relief rig must stop, as the relief rig would no longer be available to respond within the parameters required by the regulation

and the operator's approved EP and APD.

Two commenters recommend the final rule include a provision requiring operators to submit a Relief Well Drilling Plan as part of the EP application in § 550.220. The commenters further assert that such plans are critical in any case where a mutual aid agreement is used to share a relief well drilling rig, to ensure that drilling operators agree to provide relief well personnel that are trained, qualified, and prepared to provide the services they offer to share.

BSEE agrees with the commenters' concerns that useful and important information about the relief rig should be required in the EP, and believes that the final regulations are sufficiently protective as finalized, without the need for an additional plan as suggested by the commenters. Although not specifically entitled a ''Relief Well Drilling Plan'', § 550.220(c)(4) requires an operator to include with the EP a general description of how they will comply with the relief rig requirements of this section, including a description of the relief well rig, the anticipated staging area of the relief well rig, an estimate of the time it would take for the relief well rig to arrive at the site of a loss of well control, how the operator would drill a relief well if necessary, and the approximate timeframe to complete relief well operations. The EP process provides an opportunity for the public to review and comment on any submissions related to relief well operations, including the anticipated length of time to drill a relief well and complete relief well operations. Additionally, § 250.470(e) requires that the APD include a detailed description of how an operator will comply with the relief rig requirements of § 250.472. This information is required at both the EP and the APD stages because we expect an operator to have more detailed information as they move closer in time toward the exploratory drilling operations. The planning and descriptions required by these provisions ensure adequate attention to these issues.

One commenter suggests that, if a rig is strictly dedicated as a relief well rig, it still needs to be subject to the same audit, inspection, and testing requirements as an operating rig before it is approved as a stand-by rig to allow for the rig to be verified and ready for immediate use in an emergency. The commenter also recommended all records be retained for a consistent period and electronically submitted to BSEE, unless BSEE can explain the reason for recommending a different record retention schedule.

BSEE acknowledges the commenter's concern and notes that any dedicated standby rig contracted to an operator is subject to the same qualification, inspection and testing requirements as a rig with drilling activities underway. Section 250.472(a) expressly states that ''[y]our relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.'' Similarly, a dedicated standby rig is subject to the enhanced SEMS auditing requirements (*see* § 250.1920(f)) when supporting operations on the Arctic OCS. This means that the existence and effectiveness of the SEMS must also be tested on the standby rig, in addition to the active drilling rig or rigs, during the 30 day period after drilling activities commence in that field of operations.

BSEE disagrees with the comment regarding record retention. The record maintenance requirements in the proposed rule are intended to mirror, to the extent possible given the long lead times and down periods in Arctic exploratory drilling, current regulations. *See* §§ 250.426, 250.434, 250.450 and 250.467. BSEE also disagrees that electronic submission should be required and at this time we determined electronic submittal of records should remain optional.

One commenter asserted that the use of an SID should be considered only in the case of a jack-up MODU, specifically to be employed to allow the jack-up to be moved off location in the event of unmanageable hazardous ice encroachment. The commenter explains that, for floating MODUs, the SID would not add benefit, as the subsea BOP is already deployed at the seabed and the SID would require a much deeper mud line cellar, which raises additional risks for the mud line cellar construction and soil stability.

BSEE agrees with the commenter. The final rule does not require an SID, although it may be requested as alternate technology or procedure for use with a jack-up under appropriate circumstances, pursuant to § 250.141. The BOP is already subsea with a floating drilling unit, so an SID would be only marginally effective or redundant.

One commenter requested that BSEE clarify why the decision to commence relief well drilling may be made by the Regional Supervisor. The commenter asserted that such decisions should be made by the operator because it will have the best understanding of the real-time situation and the most prudent sequence of steps. The commenter suggests that, if BSEE seeks to direct active drilling operations, further clarification is required on BSEE's responsibility, accountability, and liability in the event of any incidents that occur as a direct result of those actions.

BSEE anticipates that decision-making regarding appropriate sequencing and execution of well control activities in the event of the operator's loss of well control will involve cooperation between BSEE and the operator, in light of the operator's familiarity with its circumstances, conditions, and capabilities. BSEE is not seeking to direct active drilling operations and clarifies that its role is to enforce existing regulations to protect rig personnel, the environment, and the natural resources of the OCS, which may include ordering an operator to drill a relief well. In the event of a loss of well control, the Regional Supervisor may direct the operator to commence drilling a relief well; however, it remains the operator's responsibility to manage active drilling operations, in accordance with the requirements of the regulations to respond to a loss of well control. Questions concerning liability are beyond the scope of this rulemaking, BSEE is authorized to prescribe rules and regulations that are necessary to carry out the provisions of OCSLA. (43 U.S.C. 1334(a)). Section 250.472 requires the operator to have access to a relief rig that is different from the primary rig, and that will arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control. This requirement does not specify how any relief well will be drilled. Drilling a relief well (in accordance with an approved APD and any conditions included therein) will continue to be the operator's responsibility.

One commenter questioned the authority of the Regional Supervisor to direct an operator to commence relief well operations, which is an oil spill source control activity and therefore within the jurisdictional authority of the FOSC, not the Regional Supervisor.

BSEE disagrees. The drilling of a relief well is an emergency well control measure that is conducted under regulations implementing OCSLA. As such, the BSEE Regional Supervisor has the authority to require the operator to begin relief rig operations as part of their responsibilities under the OCSLA.

One commenter requested clarification on why BOEM and BSEE are proposing additional regulations for relief rigs if they already have the existing authority to require relief rigs for exploratory drilling on the Arctic OCS. The commenter cites the NPRM preamble: ''BOEM and BSEE anticipate that we would exercise our existing authorities to require a relief rig for any future exploratory drilling on the Arctic OCS'' (see 80 FR 9948).

BOEM and BSEE have broad authority under existing regulations to impose reasonable conditions on exploration plans and drilling permits. We included the express requirements for a relief rig in § 250.472 because this provision clearly articulates that BOEM and BSEE will require access to a relief rig during all future exploration activities on the Arctic OCS, unless an operator is able to obtain approval for alternative compliance measures under § 250.141 and this final rule at § 250.472(c). This explicit requirement should allow operators to plan for all of the types of vessels, equipment, and personnel that will be required to conduct exploratory drilling operations on the Arctic OCS, and on what terms.

One commenter recommended § 250.472(a) be revised to insert the word ''safely,'' whereby an operator would be required ''to safely drill a relief well under anticipated Arctic OCS conditions.''

BSEE agrees with the commenter's premise, but notes the requirement for safe operations is the primary goal of all our regulations, and as such this obligation is captured throughout the regulations. For example, § 250.107, *What must I do to protect health, safety, property, and the environment?,* requires that all OCS operations be conducted in a safe manner and all equipment be maintained in a safe condition. Accordingly, the revision proposed by the commenter is already implicit in the regulatory requirement and an obligation of the operator, and is therefore unnecessary.

One commenter suggests that, if an operator drills a well to total depth during the drilling season prior to the time set aside for a relief well, then that time could be effectively utilized for logging and well evaluation.

BSEE disagrees. The final regulations at § 250.472 prohibit working (*e.g.,* logging and well evaluation) or drilling below the surface casing when seasonal ice encroachment is expected before the relief rig could complete relief well operations. BSEE has determined that the risk associated with drilling below or working without the ability of the relief rig to arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, is too great to allow for such operations. The operator could, alternatively, use this period to perform operations above the surface casing, such as drilling mudline cellars or top holes and setting surface casing in preparation for future operations.

What must I do to protect health, safety, property, and the environment while operating on the Arctic OCS? (§ 250.473)

BSEE proposed to add a new § 250.473 that would require performance-based measures in addition to those listed in § 250.107 to protect health, safety, property, and the environment during exploratory drilling operations on the Arctic OCS. Several comments were received on this section. BSEE has reviewed the comments and determined to finalize § 250.473 as proposed.

The majority of commenters were generally supportive of the requirements of § 250.473, and consider the finalized requirements good business practice and appropriate environmental stewardship.

One commenter suggests that the performance-based requirements could be supported by established and well known standards, such as International Electrotechnical Commission (IEC) 61508 and 61511.

BSEE has determined that no revision is needed here because these issues are addressed by our existing SEMS requirements at Part 250 subpart S, which are performance-based. The SEMS requirements are primarily based on API RP 75, which was specifically developed for the offshore oil and gas industry. The operator's SEMS must meet or exceed the standard of safety and environmental protection of API RP 75. The goal of the operator's SEMS is to promote safety and environmental protection by ensuring all personnel aboard a facility are complying with the policies and procedures identified in the operator's SEMS.

One commenter recommended adding a requirement that the operator train personnel for the environmental conditions present in the Arctic. The commenter asserted that an understanding of wind chill, frostbite, and proper safety procedures around ice-covered equipment is as necessary as having arctic-grade hydraulic fluid in the lines.

BSEE agrees that a well-trained crew plays an important role in achieving safe and professional drilling operations. We believe that the training requirements in our current regulations provide the basis for appropriate training for crews working in Arctic conditions. Section 250.1501, *What is the goal of my training program?,* requires training to ensure that employees and contractors can perform the duties associated with their jobs, and § 250.1915, *What training criteria must be in my SEMS program?,* requires implementation of a training program developed in accordance with employee duties and responsibilities for use in the SEMS programs. BSEE also believes that the requirement of § 250.473 to address human factors associated with Arctic OCS conditions can and should include training designed to address such factors. These regulatory provisions seek to ensure that operators provide for adequate training of workers specific to their positions and the conditions under which they will perform.

What are the auditing requirements for my SEMS program? (§ 250.1920)

BSEE proposed to revise existing § 250.1920 to increase the audit frequency and facility coverage for intermittent Arctic OCS exploratory drilling operations. While operators are generally required to conduct their SEMS audit every 3 years after their initial audit, BSEE proposed to require a SEMS audit of Arctic OCS exploratory drilling operations and all related infrastructure each year in which drilling is conducted, because of the particularly challenging conditions and high-risk nature of those activities. This Arctic OCS audit would require operators to ensure that all safety systems are in place and functional prior to commencing or resuming activities for a new drilling season, as well as to conduct the offshore portion of the audit while drilling is under way. An operator conducting Arctic OCS exploratory drilling operations may not combine its Arctic OCS facility audit(s) with audits of its non-Arctic OCS facilities to satisfy the facility sampling requirements incorporated into Subpart S.

Many comments were received on this section. BSEE has reviewed the comments, and made various technical edits in response to the comments. The remaining substantive provisions of § 250.1920 are finalized as proposed, as discussed herein.

Several commenters generally support this provision. Three of these commenters supported the requirement for annual SEMS audits with suggested revisions. One commenter recommended that the new provision clearly state that BSEE will ensure that any identified non-compliance in the onshore audit is remedied prior to the

start of drilling, and that the operator will be required to immediately notify BSEE of any non-compliance identified in the offshore audit so that BSEE can make an immediate and informed decision on whether to allow continued offshore operations. Another of the commenters suggested that the time frame for submittal of the audit report be expedited to 15 days, and that the Corrective Action Plan (CAP) include a plan to remedy all deficiencies or nonconformities no later than 30 days after the offshore portion of the audit. Similarly, a commenter suggested a review strategy be put in place allowing for evaluation of the management strategies and regulations instituted under this final rule during the off season to mandate that recent experience as well as advances in technology and systems design always be used to improve the effectiveness of the operator's SEMS.

BSEE agrees that an annual SEMS audit is a prudent requirement for Arctic OCS exploratory drilling. BSEE also recognizes that the audit requirement implicates more than simply having a management system in place. An audit of a good management system will identify ways that the management system is meeting its objective of hazard identification and risk management. The same audit is just as likely to identify ways that the management system is functioning but can do a better job.

BSEE is not changing the schedule for submittal of audit findings in this final rule. Developing a comprehensive audit report and effective CAP within 30 days of an audit will require considerable discipline and focus. BSEE believes that a shorter time frame would compromise the quality of both submittals. In addition, the time frame to complete any proposed corrective actions should not be specified in the rule, as the appropriate time frame for correction is largely dependent upon the nature of the nonconformity. This will continue to be a subject for discussion between the operator and BSEE as currently allowed by the regulation. With respect to BSEE's ability to ensure timely compliance, finalized § 250.1920(g) provides that, ''if BSEE determines that the CAP or progress toward implementing the CAP is not satisfactory, BSEE may order you to shut down all or part of your operations.''

BSEE also does not believe that it is necessary to specify that off-season evaluation of the SEMS needs to be performed. Operators have discretion within their own management systems on how to identify and prioritize continual improvement opportunities, and our specifying how to do this could be counterproductive. Finally, BSEE believes that the schedule for submittal of the audit findings will allow BSEE to intervene quickly if a management system is not in place, as when an operator's continual improvement efforts appear inadequate.

Several commenters request that BSEE remove the annual auditing requirements of § 250.1920(b)(5). The commenters assert that such a frequency of auditing is not needed, has not been justified, and will not have an impact on safety or compliance because an operator's SEMS program does not typically change on an annual basis. In addition, commenters state that existing BSEE regulations require an audit of the SEMS program on a three-year cycle, which has worked effectively for operations in the Gulf of Mexico and they assert should be more than adequate for operations in the Arctic OCS. One commenter suggests that an annual audit frequency may actually reduce health, safety, security, and environmental performance, and requiring an annual SEMS audit on existing operations will result in added time delay to conduct audits without any demonstrated improvement to safety.

BSEE disagrees with these comments. Operators engaging in exploratory drilling on the Arctic OCS will be managing risks that are novel and untested compared to those encountered in the Gulf of Mexico. Arctic operations are seasonal and will include mobilization and demobilization activities each year within short time windows. Changes to an operator's management system (both in design and in the personnel who will be relied upon to implement it) are likely to be required as new hazards are recognized and managed, and as contractors rotate in and out of the field. Accordingly, an operator's Arctic SEMS program will likely change over the course of a year. Annual auditing is a way to determine if the organization is continually improving its management system as it gains experience with the new risks and the changing environmental and organizational conditions. If an operator finds that audit results do not contribute to improved approaches to safety and environmental protection, then it is possible that the audit approach needs to be changed rather than resorting to a less frequent audit.

Several commenters suggest additions to the content of SEMS audits for exploratory drilling operations on the Arctic OCS. One of the commenters suggests the SEMS audit should be extended to address the status of key barriers and assess ice management, as well as evaluate the Arctic operator's safety culture. Another of the commenters asked that the SEMS audit include a focus on contractor management and oversight. One of the commenters suggests the proposed regulatory text be revised to include a reference to the onshore portion of the audit incorporating a physical audit of all major equipment proposed in the EP and APD (including at a minimum the drilling rig, SCCE, relief rig, and support vessels) to verify this equipment is ready and capable. The commenter also recommended the revision address the offshore portion of the audit, including requiring a physical audit of all equipment used to execute the EP and APD in the Arctic OCS while drilling is underway. The same commenter asked that the SEMS audit require an audit of 100 percent of the equipment instead of 100 percent of the facilities.

BSEE agrees that those who audit Arctic operations need to examine contractor management elements of their SEMS, as well as review the barrier analysis and barrier readiness aspects, including ice management, weather and ice forecasting, ice and marine mammal monitoring, and response to ice encroachment. BSEE notes, under existing §§ 250.1914 and 250.1924, BSEE has broad authority to require operators on the Arctic OCS to provide BSEE with appropriate contractor information, such as the names of contractors and the specific scope of their duties and timelines for performance in support of an operator's drilling activities. For example, if an operator planned to use a contractor for waste disposal, cementing, or logging, BSEE would expect the operator to inform BSEE of this intent, along with any other operations contracted out, and the names of those contractors. BSEE intends to work with the Accreditation Bodies it names pursuant to § 250.1922 to define and hold auditors accountable for evaluating the management system's effectiveness in addressing these risk areas.

BSEE disagrees that the scope of the audit should include inspection of equipment. The purpose of a management system audit is to determine if the processes and systems adopted by an operator to manage risk are in place and effective, not to test and inspect the functionality of every piece of equipment within the management system. BSEE conducts thorough facility and equipment inspections through its own inspection program. *See, e.g.,* §§ 250.130 through 250.133.

One commenter expressed concern that there would be a shortage of

qualified independent third party auditors.

BSEE disagrees that a possible shortage of qualified auditors should be a basis for challenging the annual SEMS audit requirement on the Arctic OCS. The commenter did not provide evidence that there is or will be a shortage of qualified auditors, or that the marketplace would not be able to respond appropriately.

One commenter requested further clarification on the associated responsibility, accountability and liability BSEE will assume in the event of any incidents occurring as a direct result of what the commenter describes as BSEE seeking to direct active drilling operations. The commenter urges BSEE to leave key operational decision-making in the hands of the operators and focus the regulations on ensuring that drilling plans and operations are risk based and fit for purpose for every proposed location.

BSEE does not direct active drilling operations, nor intend to do so in the future through this rule. Operators responsible for directing the drilling operations are required to do so safely and in accordance with the regulations. BSEE has the authority to require compliance with the regulations, but in doing so does not assume any accountability or liability for incidents arising from the regulated operations. It is the operator's responsibility to conduct its activities both safely and in accordance with its regulatory obligations. Operators must also have access to all of the information needed to make their own decisions on how to mitigate safety and environmental impacts from the hazards they will face. One purpose of the SEMS audit is for the operator to gain a third-party assessment of their own ability to effectively manage risks. BSEE does not use the results of the SEMS audit to tell operators how to manage the risks, but instead evaluates those results as one part of its oversight responsibilities to ensure that the operators have systems in place that are effectively risk-focused and fit for purpose.

One commenter asked that BSEE consider a Safety Case approach to ensure functionality of Health Safety and Environment and Quality management systems, and compliance of rigs and contractors, similar to the approach established on the Norwegian Continental Shelf and in the United Kingdom.

BSEE declines to adopt this suggestion. BSEE has adopted a hybrid approach to safety and environmental regulation on the OCS. BSEE and BOEM have determined that Arctic exploratory drilling operations should be guided by a number of specific requirements to ensure protection of workers and the environment. We note that the final rule clearly allows for specific requirements to be met by employing new and emergent technology, when appropriate. Given the significant risks associated with Arctic drilling operations, complete reliance on a safety case approach, in the view of BSEE and BOEM, does not offer enough regulatory oversight.

Oil Spill Response

Part 254—Oil-Spill Response Requirements for Facilities Located Seaward of the Coast Line

Definitions. (§ 254.6)

BSEE proposed to insert in the proper alphabetical order new definitions for *Adverse weather conditions, Arctic OCS* and *Ice intervention practices* to existing § 254.6. One comment was received to the definition for *Adverse weather conditions* and is discussed below. No other comments were received on the proposed addition of the definitions and the provisions are finalized as proposed.

One commenter claimed that the revised definition for Adverse Weather Conditions disregards the safety of responders and would set in place operating limits that would delay the cessation of response activities until equipment is destroyed or responders are fatally injured. The commenter suggests that BSEE replace the definition with language adopted from the State of Alaska's regulations, which require a plan holder to define realistic maximum response operating limitations, as per 18 AAC 75.425(e)(3)(D).

BSEE disagrees with this comment. The final rule adds the terms ''extreme cold, freezing spray, snow, and extended periods of low light'' to the list of conditions in the existing definition that may degrade the operating environment on the Arctic OCS. Adopting these terms in the final rule provides a more thorough description of the types of challenges a plan holder's response resources must be prepared to address in responding to a discharge on the Arctic OCS, but in no way establishes operational limits, and certainly does not create any expectation that responders will continue to operate in life threatening conditions. Operating conditions must be continuously evaluated and monitored during a response to ensure effective operations, but only when it is safe for responders to do so. The revised definition continues to state that Adverse Weather does not include situations where it would be dangerous to continue responding. The State of Alaska's cited regulations require the plan holder to define the maximum operating limitations for a mechanical recovery-based response, and to identify mitigating measures that may be instituted when those parameters are exceeded. This State requirement in 18 AAC 75.425(e)(3)(D) has a very different focus and intent and is not appropriate language for use in revising the definition of Adverse Weather Conditions for purposes of implementing the OPA.

OSRPs for Facilities Located in Alaska State Waters Seaward of the Coast Line in the Chukchi and Beaufort Seas. (§ 254.55)

BSEE proposed to add a new § 254.55 requiring the OSRP for any facility conducting exploratory drilling from a MODU in Alaska State waters seaward of the coast line within the Beaufort or Chukchi Seas to address the additional requirements set forth in the new subpart E, as finalized in this rulemaking. BSEE has authority under the CWA over oil spill response plans related to operations seaward of the coastline, including on state submerged lands. 33 U.S.C. 1321(j)(5); E.O. 12777; 30 CFR part 254, subpart D. Some requirements in subpart E address planning and exercises related to the use of source control and subsea containment equipment such as capping stacks or containment domes. Operators are required to have access to and use this equipment when conducting exploratory drilling from a MODU on the Arctic OCS, pursuant to finalized regulations in part 250, but those conducting similar activities in State waters are not currently subject to the same requirements. The State of Alaska, however, has State requirements for source control. As such, a response plan covering operations in State waters of the Beaufort or Chukchi Seas must address how the source control procedures selected to comply with State law would be integrated into the planning, training, and exercise requirements of proposed §§ 254.70(a) and 254.90(c).

Several comments were received on this section. BSEE has reviewed the comments and determined to finalize § 254.55 as proposed for the reasons stated herein.

One commenter requested that BSEE closely coordinate its OSRP requirements with the State of Alaska's requirements.

BSEE agrees, and for offshore facilities in State waters seaward of the coast line, BSEE will consult with the State to

coordinate planning processes where possible. We note this rulemaking does not alter in any way the existing authorities or jurisdiction of BSEE or the State of Alaska. In addition, we note that, pursuant to existing § 254.53, operators in State waters may still rely upon OSRPs developed in accordance with the laws or regulations of Alaska, with certain modifications. Additionally, BSEE has a separate regulatory study underway that is evaluating the use of more specific deployment and response capability standards for each OCS region where oil and gas exploration and production is occurring. BSEE will review the State of Alaska's standards for facilities in State waters as part of this study, and will harmonize any future standards when it deems it is appropriate.

One commenter stated that the term ''source control'' is different than the term used in State requirements, which is ''contain and control'', and that using different terms will be problematic.

BSEE's position is this rulemaking addresses Federal requirements for offshore facilities in State waters seaward of the coast line, and does not impact state requirements. The State and Federal terms, while slightly different, are effectively similar in nature, and should not create any confusion for plan holders with respect to complying with either State or Federal regulations. While it is beneficial to use harmonized terms whenever possible between State and Federal regulations, it is just as important that Federal regulations use terminology that is consistent across various Federal rules and agencies. The term ''source control'' is defined in the National Contingency Plan as the construction, installation and startup of actions necessary to prevent the continued release of hazardous substances or pollutants or contaminants into the environment.[44] Source control is a consistently used term in other response-oriented doctrinal publications, such as the National Preparedness for Response Exercise Program (PREP) Guidelines and the USCG Incident Management Handbook.

Subpart E—Oil-Spill Response Requirements for Facilities Located on the Arctic OCS

Purpose. (§ 254.65)

A new § 254.65 was proposed to state the purpose for subpart E, described as establishing additional requirements for preparing OSRPs and maintaining preparedness for facilities conducting exploratory drilling operations from a MODU on the Arctic OCS. No comments were received on the proposed addition of this section and, with exception of one minor technical edit, the section is finalized as proposed.

What are the additional requirements for facilities conducting exploratory drilling from a MODU on the Arctic OCS? (§ 254.70)

BSEE proposed adding § 254.70 addressing general oil spill response planning requirements for operators using MODUs to conduct exploratory drilling on the Arctic OCS. These requirements include incorporating the support mechanisms for capping stacks, cap and flow systems, containment domes, and other similar subsea and surface devices and equipment and vessels, required by finalized § 250.471, into oil spill response incident action planning. They would also require operators to address the influence of adverse weather conditions on responders' health and safety during spill response activities. Finally, they would require operators, prior to resuming seasonal exploratory drilling activities, to review their OSRPs, and modify as necessary, to address changes to the location or status of response resources or the arrangements for supporting logistical infrastructure arising from extended periods of time without drilling.

Several comments were received on this section. BSEE has reviewed the comments and with the exception of one technical edit, the provisions of § 254.70 are finalized as proposed for the reasons discussed herein.

Many commenters recommend that BSEE should include an opportunity for public review and comment for OSRPs that address operations on the Arctic OCS.

BSEE disagrees. The National Response System that was set up under the CWA and the OPA establishes a system of plans, including a National Contingency Plan, regional contingency plans, area contingency plans, and facility and vessel response plans. National, regional, and area level plans all set policy on the use of oil spill countermeasures and all relevant strategies, and identify how sensitive resources must be protected. Regulatory agencies promulgate regulatory requirements for industry OSRPs, consistent with these higher-level plans requiring industry plan holders to have access to the requisite amounts and types of response capabilities. Agency review and approval of these plans is limited to ensuring the plans are consistent with national, regional, and area level guidance and ensuring the plans meet the pre-established regulatory requirements for capabilities and preparedness arrangements. Public comment and review is not necessary for the Agency to complete its review of the OSRP for compliance with the regulations, nor is there a meaningful role for the public where the pre-established standards of review leave little to no room for discretion. Under this existing paradigm, none of the industry response plans regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA), EPA, USCG or BSEE are subject to a public review and comment process. BSEE believes the most appropriate opportunities for public participation and comment on the relevant response issues are during the public comment periods associated with the oil and gas lease sales and EPs, public comment periods during the rulemaking process for establishing industry response plan regulatory requirements, and through interaction with the Area Committees, who develop the local Oil Spill Area Contingency Plans that provide guidance on the use of spill response countermeasures as well as protection strategies for specific sensitive habitats and species. In the case of the Arctic OCS, BSEE encourages interested parties to engage with the Alaska Regional Response Team, whose members include: The USCG; NOAA; Federal Emergency Management Agency; Federal Aviation Administration; General Services Administration; State of Alaska Department of Environmental Conservation; EPA; and Departments of Agriculture, Defense, Energy, State, Health and Human Services, Interior, Justice, and Labor, as well as the Northwest Alaska and North Slope SubArea Committees.

One commenter suggests that BSEE should develop the OSRP requirements using a risk-based environmental assessment process and design the response capabilities to address the specific risks of a spill from the offshore facility.

BSEE agrees with the commenter's concern, but notes the baseline requirements for an OSRP within § 254.26 already contain many provisions that are founded upon risk assessment processes. For example, plan holders must use oil spill trajectories from their offshore facility to assess any spill risks to resources and habitats, and design response capabilities appropriately. While this rulemaking adds additional detail that is necessary

[44] 40 CFR 300.5; *See generally* 40 CFR part 300, National Oil and Hazardous Substances Pollution Contingency Plan.

to ensure the oil spill preparedness measures are adequately designed for operating in the Arctic environment, it does not impose a new system of risk assessment processes for developing OSRPs upon plan holders that is outside of what currently exists in Part 254 or was proposed in the NPRM. Plan holders are free to adopt risk-based methods in developing their OSRP response strategies, as long as those strategies are in compliance with the regulatory requirements.

One commenter asserted that the type and number of resources that should be maintained in an area should reflect the most probable spill events that might occur.

BSEE disagrees. The OPA and BSEE's OSRP regulations require industry to plan for their WCD to the maximum extent practicable as a planning standard, and not for the size of their most probable spill, which would be considerably smaller. While response resources are strategically staged throughout the coastal zone near OCS regions where drilling occurs, BSEE acknowledges that in some cases equipment will be cascaded in from more distant areas in order to respond to a WCD, especially in the Arctic OCS.

One commenter suggests the regulations should allow for all types of response mechanisms to be in place, including the use of dispersants and in situ burning.

BSEE agrees industry OSRPs should include provisions for all of the oil spill response capabilities that are allowed for and consistent with the guidance contained within the relevant Regional and Area Contingency Plans (RCPs/ACPs). In the Arctic OCS, the guidance regarding, and strategies for, the use of dispersants and in situ burning is contained within the Unified Alaska Plan and the North Slope SubArea Contingency Plans. BSEE's OSRP regulations currently allow for the listing of both dispersants and in situ burning capabilities within industry OSRPs. A regulatory study entitled, ''Oil Spill Response Equipment Capabilities Analysis,'' is currently underway that is considering additional requirements for ensuring the availability of these spill countermeasures in all areas of the OCS where drilling is occurring or may occur, including the Arctic.

One commenter suggested that the duration of a WCD required by § 254.26(a) for drilling operations should be extended beyond 30 days to whichever is greater, a period of 45 days or the time it would take to drill a relief well. The commenter further recommended that the method to calculate the WCD daily flow rate should be amended and based on offset well data; if no offset well is available, the commenter recommended that minimum default values of 61,000 barrels of oil per day for wells in the Chukchi Sea, and 25,000 barrels of oil per day for wells in the Beaufort Sea, should be adopted.

BSEE agrees in part. Based on the lessons learned from the *Deepwater Horizon* response, BSEE released National Notice to Lessees and Operators of Federal Oil and Gas Leases and Pipeline Right-of-Way Holders (NTL) No. 2012–N06, ''Guidance to Owners and Operators of Offshore Facilities Seaward of the Coast Line Concerning Regional Oil Spill Response Plans.'' NTL No. 2012–N06 encourages operators to identify sources for supplies and materials that can support a response to an uncontrolled spill lasting longer than 30 days. However, BSEE has determined that further study is required before revising 30 CFR part 254 to extend the duration of a WCD. BSEE has a regulatory study entitled, ''Oil Spill Response Equipment Capabilities Analysis,'' underway to consider various options for amending the period of time for which an operator must plan to support response operations. With regard to daily flow rates, § 254.47 states that an operator must calculate the size of their WCD scenario as the daily volume possible from an uncontrolled blowout, but does not go into detail about how that flow rate calculation must be made. Rather, the daily flow rate information referenced in the OSRP is based upon data generated earlier in the permitting process for the associated EP as required by BOEM in § 550.213(g) and NTL No. 2015–N01, ''Information Requirements for Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents on the OCS for Worst Case Discharge and Blowout Scenarios''. BSEE does not believe that it would be appropriate to institute minimum default values in lieu of the prescribed methodology.

Two commenters indicated the regulations should provide more detailed guidance on what oil spill planning and response capabilities should be required to adequately respond to an oil spill in the Arctic. One of the commenters provided detailed recommendations for what those requirements and capabilities should entail.

The existing regulations in § 254.26 provide a broad performance-based planning standard for establishing a plan holder's WCD identifying the anticipated impacts, and ensuring the availability of enough response and supporting resources to protect or clean up the environment from such a discharge. BSEE is reviewing the possibility of providing more detailed requirements for response capabilities in a future rulemaking, and will consider the recommendations provided in these comments as an input for that process. Until that time, it is the plan holder's responsibility to develop response capabilities that will satisfactorily meet the existing planning standard.

One commenter argued that most drilling in the Arctic is in extremely shallow water from gravel islands, and that use of SCCE equipment in those cases is not practicable.

BSEE agrees. The SCCE requirements of this rulemaking only apply to MODUs conducting exploration drilling, and therefore would not apply to shallow water drilling from gravel islands.

Two commenters assert that adding SCCE information to the OSRP would confuse responders and unnecessarily increase the size of the OSRP. The commenters suggest that SCCE information should be kept in a separate planning document, and one of the commenters specifically recommended that OSRPs reference well containment plans instead.

BSEE agrees in part. SCCE are critical capabilities required for certain plan holders in order for them to meet their requirements in existing § 254.26(d) for responding to their WCD. Further, SCCE will be deployed and utilized alongside spill response equipment, necessitating coordinated planning for an integrated approach to a loss of well control. As such, OSRPs must include certain essential information about SCCE capabilities. BSEE agrees that most SCCE information can be maintained in separate well control-oriented planning documents (as required by § 550.220(c)(3) (EPs) and § 250.470(f) (APDs)) as long as they are properly referenced in the OSRP. However, incidents, such as the Macondo Well blowout, demonstrate that source control activities need to be better coordinated with the overall management of the larger incident and other response operations, and they validate the need for additional source control information in the OSRPs. Accordingly, the OSRP should outline how the management structure established for the overall incident response will coordinate SCCE activities. BSEE believes the inclusion of this critical information in the OSRP will improve clarity for all responders rather than create confusion, and will

not appreciably increase the size of the OSRP documents.

One commenter recommended the Arctic-specific regulations contain milestones that ensure timely deployment of well control equipment in concert with oil spill response equipment.

BSEE agrees and has determined the final rule addresses the commenter's recommendation. Regulatory requirements finalized in other parts of this final rule, such as §§ 250.470, 250.471 and 250.472, contain new standards for the deployment of well control equipment in the Arctic and include timelines for deployment. We note, however, that although the commenter's concern is addressed in part 250 of this final rule, part 254 currently does not contain any specific timelines for the deployment of spill response equipment.

Two commenters request that BSEE require plan holders to describe how they will respond in adverse weather conditions.

BSEE agrees. Existing § 254.26(d) requires plan holders to discuss how they will respond to their WCD scenario in adverse weather conditions. The purpose of subpart E is to provide additional regulatory detail to address Arctic-specific issues and challenges. The finalized requirements in § 254.70(b) require an operator to describe how they will address certain human factors, such as cold stress and cold-related conditions that are likely to become challenges due to the adverse nature of Arctic OCS conditions. Additionally, the finalized requirements in § 254.80(a) and (b) require an operator to describe how they will adapt and sustain their response techniques during adverse conditions that occur in the Arctic OCS operating environment.

One commenter recommended that operators be required to provide detailed statistical assessments for identifying curtailment thresholds that will limit operations or pose safety hazards to responders in Arctic conditions, and that this assessment should be used to establish the end of season operational dates at § 550.220(c)(6).

BSEE agrees in part. Section 254.70(b) requires operators to describe how they will address Arctic challenges in adverse weather conditions. While it is prudent for operators to identify and address recommended operating limits in their safety procedures, decisions to suspend response operations due to safety concerns must be made on a case by case basis and must consider all the conditions in place at that point in time. Operational safety decisions cannot be projected forward based on a statistical analysis of past seasonal conditions; however, the general limitations on an operator's' ability to conduct an oil spill response due to expected site conditions are considered by BOEM when establishing end-of-season dates.

One commenter suggests the requirements of § 254.70 should be more performance-based and focus on management practices.

BSEE agrees in part. The OSRP regulations are designed to strike a balance between performance-based standards that afford an operator the flexibility to develop an OSRP that meets the specific needs of its offshore facility and more detailed prescriptive requirements ensuring an OSRP meets the underlying statutory requirements. Many of the provisions contained throughout part 254 are performance-based in nature, while many others address the management practices of the operator to organize and respond to their WCD. BSEE believes that § 254.70 appropriately strikes that balance as written.

One commenter asserted that the provision in § 254.2(b), which allows a facility to operate while BSEE reviews the plan, should be removed for operations in the Arctic OCS.

BSEE agrees in part, however the proposed rule did not contain any amendments to the requirements of § 254.2. These administrative practices have been successfully followed for many years for OSRPs in other OCS regions, and are particularly well suited for certain situations, such as the transfer of ownership of an existing facility to a new operator who will now operate the facility under the new owner's existing regional OSRP. BSEE acknowledges that the provision in § 254.2(b) is not as well suited for the review and approval of new OSRPs covering exploratory drilling in the Arctic, where the challenges associated with operating in this frontier environment have made the review and approval of OSRPs more complex and controversial in the public eye. As such, BSEE will look to clarify the overall applicability of these procedures in a separate rulemaking that will update Part 254, including § 254.2. Finally, it should be noted that all operators on the Arctic OCS in recent years have had their OSRP approved well in advance of conducting any drilling operations at their lease sites.

One commenter asserted that all existing OSRPs should be updated to meet the new requirements of this rulemaking within 90 days.

BSEE disagrees. The final rule states that the requirements contained in this rulemaking will become effective 60 days after the date of publication in the **Federal Register**. At the time of finalizing this rulemaking, there currently are no approved or pending OSRPs involving exploratory drilling on the Arctic OCS from a MODU.

What additional information must I include in the ''Emergency response action plan'' section for facilities conducting exploratory drilling from a MODU on the Arctic OCS? (§ 254.80)

BSEE also proposed to create a new § 254.80 focusing on additional information requirements for the emergency response action plan section of an OSRP when the operator proposes to conduct exploratory drilling operations from a MODU on the Arctic OCS. The additional requirements would include specifics regarding ice intervention practices, staging considerations, and tracking abilities.

Several comments were received on this section. BSEE has evaluated the comments and made various technical edits as discussed herein. Otherwise, the substantive provisions of § 254.80 are finalized as proposed.

Many commenters assert that the regulations must include requirements ensuring Arctic-grade response capabilities for equipment, materials and personnel capable of operating in Arctic conditions, including fog, adverse sea states, and ice.

BSEE agrees and has determined this recommendation is met in our existing regulations. Section 254.26(e) states that operators must ensure that the response equipment, materials, support vessels, and strategies listed are suitable, within the limits of current technology, for the range of environmental conditions anticipated at your facility. Furthermore, § 254.80(a) requires that operators, who are developing ice intervention practices, must consider the use of specialized tactics, modified response equipment, ice management assist vessels, and technologies for the identification, tracking, containment and removal of oil in ice.

One commenter requested that BSEE delete the requirements of proposed § 254.80 as redundant to existing regulations in part 254. The commenter asserted that the requirement for ice intervention practices is redundant with the requirements of existing § 550.220(b), which requires an Ice Management Plan (IMP), a component of the Critical Operations and Curtailment procedures, and that the OSRP should simply reference the procedures contained within the IMP.

BSEE disagrees. The proposed requirements in § 254.80 address

aspects of oil spill response preparedness, as opposed to operational preparedness, that are specific to meeting the challenges of operating in the Arctic OCS. While the requirements finalized here somewhat mirror the basic oil spill preparedness requirements existing in the OSRP regulations, they are not redundant of the IMP and add an important layer of additional detail that is necessary to set expectations for preparedness to respond to spills in the Arctic. The IMP addresses how ice floes will be managed to protect drilling operations and procedures for stopping, and if necessary, disengaging, drilling operations due to the encroachment of sea ice. Ice intervention practices have a completely different purpose, and are focused on improving the effectiveness of spill response countermeasures in the presence of sea ice. Both are distinct and necessary elements of the regulations.

One commenter recommended that ice intervention practices should address how response equipment will address challenges associated with response in the Arctic.

BSEE agrees. The intent of the requirement for a description of the operator's ice intervention practices was to ensure plan holders evaluated their capabilities and ensured they are adequately prepared and trained to effectively operate in expected Arctic conditions.

One commenter asserted that the requirement for ice intervention practices is limited to mechanical recovery.

BSEE disagrees with this statement, and reiterates that the operator should develop ice intervention practices for each response countermeasure listed in the OSRP. The preamble discussion in the NPRM states that an operator's ice intervention practices should improve oil encounter rates for all removal or mitigation techniques, including dispersants and in situ burning.

One commenter asserted that BSEE should conduct further studies regarding the challenges involved with responding to a spill in the Arctic, such as responding in the presence of ice.

BSEE agrees and is continually reviewing ongoing research study reports as well as funding numerous studies of its own to better understand all aspects of responding to oil spills in Arctic conditions. BSEE uses that information to better inform its efforts to develop regulations and assess a plan holder's preparedness to respond to oil spills.

One commenter recommended that, in addition to requiring the development of ice intervention practices, BSEE provide specific recovery equipment performance standards for recovering oil in the Arctic. Specifically, the commenter recommended that BSEE adopt a standard similar to the State of Alaska requirement at 18 AAC 75.445(g)(5).

BSEE agrees with the intent of the comment, but has determined the commenter's concern is addressed in existing regulations. BSEE reviewed the standard contained within 18 AAC 75.445(g)(5) and found that the existing requirements in § 254.44 already establish an equipment performance planning standard that is equivalent in nature. In addition, BSEE has an ongoing regulatory study underway to evaluate potential revisions to the requirements contained in § 254.44, including a revised equipment planning standard that would be based on oil encounter rate and recovery system-based performance. This revised planning standard may be incorporated into the regulations for all OSRPs, including those in the Arctic OCS, at a later date in a future rulemaking.

Several commenters recommend the provisions in the Arctic-specific regulations should be informed by research into oil behavior and spill response techniques in ice, and that flexibility must exist to select the most effective strategies in context of the spill situation.

BSEE agrees with both of these points. Both government and industry are conducting extensive research on oil behavior and the use of appropriate spill response techniques in ice. BSEE's development of its regulatory requirements, as well as its plan review and approval processes, is informed by this information. BSEE also supports the use of a process to compare the environmental outcomes associated with using various response techniques and countermeasures in order to assess and select the most appropriate response technologies for use during an event. However, the selection and use of response technologies during a spill event is governed by EPA regulations contained within the NCP, and by the FOSC, which is a pre-designated senior USCG official. BSEE is not dictating the selection or use of any particular strategies for responding to any specific spill situation through its regulations or the OSRP process.

One commenter suggested that OSRPs should include information that outlines when dispersants will be used and when their use will not be allowed.

BSEE disagrees. A plan holder does not have the authority to prescribe the conditions or required outcomes that must be present for dispersants to be used during a response. The use of dispersants is governed by the provisions of the NCP, as supplemented by RCPs and ACPs, and implemented on a case by case basis under the direction of the FOSC.

One commenter asserted that the OSRP regulations currently limit the response to mechanical spill recovery techniques only, and that BSEE should allow plan holders to use other response countermeasures when their use is appropriate. The commenter also indicated that the OSRPs should describe how those countermeasures will be used in the presence of sea ice and other Arctic conditions.

BSEE agrees that plan holders should plan for and prepare to use all available technologies and countermeasures to effectively mitigate the impacts of a discharge from their facilities, and that such planning and preparation should account for the presence of sea ice and other Arctic OCS conditions. While the regulations require the inclusion of mechanical recovery resources in the response plans, the regulations also allow for the listing of dispersants, in situ burning, and other response countermeasures in the plans, when using those countermeasures would be consistent with the strategies contained within the RCPs and ACPs for the area in which the facilities are operating. The procedures in the RCPs and ACPs provide the processes that a plan holder and the FOSC must follow in selecting the proper response countermeasures for a given situation. BSEE also agrees that OSRPs for facilities operating in the Arctic should describe how the plan holder would implement each countermeasure in ice. The new requirement to describe ice intervention practices in § 254.80(a) requires the plan holder to describe how they will effectively use each countermeasure in the presence of sea ice.

One commenter recommended that strategies and tactics listed in the OSRP, including use of dispersants and burning, should be based on the latest regional-specific research, historical oil spill data, field tests conducted by the operator or its Oil Spill Response Organization (OSRO), and exercises, and environmental analysis.

While BSEE agrees that response strategies and tactics should be informed by all the methods recommended by the commenter, BSEE disagrees with their assertion that plan holders are responsible for gathering this information, or that plan holders are responsible for field testing or validating these strategies and tactics as part of the process of developing and

submitting their OSRPs. Rather, response strategies and tactics are developed and approved for use geographically and temporally, and should be exercised and validated by the Regional Response Teams and Area Committees, and should be contained in the appropriate RCPs and ACPs. As such, Regional Response Teams and Area Committees would be the appropriate entities to review ongoing trends, new research or testing information, and to adjust the response strategies in the RCPs and ACPs accordingly. While OSRPs must be consistent with the strategies and tactics identified for use in the relevant RCPs and ACPs, their focus and purpose is to address how the operator will supply, manage, and sustain the necessary response resources for implementing the strategies and tactics.

Two commenters recommend that the requirements in § 254.80 should contain specific protection and response strategies and maps for environmentally sensitive areas and subsistence resources. One of the commenters further suggests that plan holders should have response personnel and equipment pre-staged near those sensitive sites, and that the strategies and equipment should be tested through a plan holder's exercise program, prior to being included in an OSRP.

While BSEE agrees protection and response strategies for sensitive resources are a critical part of oil spill response, BSEE disagrees that these strategies should be developed by industry plan holders, nor does BSEE believe it is feasible for a plan holder to pre-stage personnel and equipment throughout the Arctic wherever sensitive resources might be located. The correct place for the development of protection and response strategies for sensitive areas and resources, in accordance with guidance in the NCP, is in the ACP. In this case, the appropriate place would be within the North Slope SubArea Contingency Plan. Existing regulations do, however, require that operators address strategies for protecting environmentally sensitive areas in their OSRPs. *See, e.g.,* §§ 254.23(g) and 254.26(c). BSEE does not believe that further treatment of this issue is necessary in § 254.80. The Alaska Regional Response Team and the North Slope SubArea Committee are responsible for testing and validating these strategies. It is not the responsibility of an industry plan holder to develop these geographical response strategies, nor is it a requirement for a plan holder to test any strategies listed in an ACP prior to referencing them in their OSRP.

One commenter requested clarification regarding what areas under section § 254.80(b) would qualify as ''areas of the Arctic OCS where a planned shore-based response would not satisfy § 254.1(a).'' This commenter also requested clarification of the term ''remote and limited infrastructure'' under § 254.80(b)(2), indicating that this term is ambiguous and could change based on location and the future progress of the Arctic infrastructure on the coastline.

BSEE acknowledges there is a subjective element to these provisions that must be evaluated by the plan holder and agency plan reviewers on a case-by-case basis. The intent of the provisions is to ensure that plan holders take the steps necessary to ensure they can mobilize and sustain a significant oil spill response effort in the Arctic and overcome the obstacles presented by the extremely limited infrastructure that exists throughout the entire Arctic region. Given the development along the Arctic coast, the entire Arctic OCS region would qualify for both provisions. BSEE acknowledges this situation could change in the future, and thus adopted language that would allow the application of these provisions to evolve once an appropriate level of infrastructure is developed and put in place. BSEE can document and communicate such situations in the future through an NTL or other communications with plan holders as such need arises.

One commenter asserted that situations where an entirely offshore-based response is necessary, with no support from onshore resources, are not unique to the Arctic.

BSEE agrees this situation does exist, to a degree, for certain facilities located far offshore in the Gulf of Mexico. However, in the Arctic, unlike the Gulf of Mexico, nearly all OCS exploratory drilling falls into this offshore-based category due to the lack of shore-based supporting infrastructure in the region. As such, BSEE believes it is appropriate to have specific planning requirements to address this aspect of responding on the Arctic OCS.

One commenter suggests replacing the phrase ''adverse weather conditions'' in § 254.80(b)(1) with the concept of ''realistic maximum response operating limits'' (RMROL) from 18 AAC 75.425(e)(3)(D).

BSEE agrees plan holders must research the environmental conditions for the Arctic OCS area they will be operating in and ensure that the resources they acquire will be capable of sustained activity in those conditions; however, BSEE does not intend to establish specific operating criteria or limits for such equipment. The requirement for response equipment to be capable of operating in conditions up to and including adverse weather is a longstanding element of OPA requirements and is sufficiently covered by other parts of BSEE part 254 regulations. While the ability to operate in adverse conditions is an important element of § 254.80(b)(1), the real purpose of this requirement is to establish an offshore-based capability that can function without constant resupply from shore side infrastructure.

One commenter asserted that requiring the pre-staging of response equipment reduces the flexibility of the incident commander to respond effectively.

BSEE disagrees. Pre-spill planning, including the identification of pre-staging sites, is critical to an effective incident response. Incident commanders always have the flexibility to adapt the pre-spill planning in the OSRPs to meet the emergent needs of responders during a real incident. Therefore, BSEE does not believe that pre-staging response equipment reduces the flexibility of the incident commander to respond effectively.

One commenter asserted that additional response resources and training of local responders are needed along the coast of the State of Alaska. One commenter recommended that agencies with oil spill response responsibilities study various locations along the U.S. Arctic coast where equipment could be stored and staged, suggesting that such emplacements would lead to improved response times for equipment and potentially reduced the environmental impacts of an oil spill.

BSEE agrees that staging of equipment at strategically located depots along the State of Alaska coast could have a positive impact on oil spill responses that occur in the Arctic. However, the staging of response resources is primarily dependent upon the needs of each individual plan holder to enable them to respond to their WCD. As such, staging of response resources falls to the discretion of the plan holder and their OSRPs, with agencies reviewing their arrangements to ensure they will meet the planning standards in the regulations. To provide flexibility in allowing plan holders to meet their individual needs, the regulations do not mandate the use of any particular staging location(s) for equipment and personnel that must be used to meet response planning standards.

One commenter asserted that all response resources should be located in

the Arctic prior to the start of drilling operations unless a viable logistics plan is in place for cascading in additional response supplies.

BSEE agrees. Paragraphs (a) and (b) of § 254.80 require operators to list and describe their resources that will be offshore-based in the immediate area of the drilling operations, as well as their logistics resupply chains that will effectively address the remote and limited infrastructure that exists in the Arctic.

One commenter recommended the OSRP contain requirements for pre-staging equipment in the Russian Arctic, as well as procedures for moving response resources into waters under the jurisdiction of Russia.

BSEE disagrees. The preparedness and response requirements related to an oil spill located in Russian waters are governed by the laws and regulatory requirements of Russia. The movement of resources and the coordination of response activities between the two countries in the event of a transboundary oil pollution incident will be addressed by the U.S. Department of State and will follow existing bi-lateral and multi-lateral agreements that are in place for responding to transboundary spills in the Arctic.

What are the additional requirements for exercises of your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS? (§ 254.90)

BSEE proposed to create a new § 254.90 that would require operators to incorporate the additional requirements contained within §§ 254.70 and 254.80 into their oil spill response training and exercise activities; would require operators to provide notice of the commencement of covered operations; and would clarify the authority of the Regional Supervisor to conduct exercises, prior to and during exploratory drilling operations, to test response preparedness. These requirements are all essential to ensuring and verifying an operator's readiness to conduct response activities on the Arctic OCS.

Several comments were received on this section. BSEE has reviewed the comments and determined to finalize § 254.90 as proposed for the reasons stated herein.

One commenter recommended that operators conduct mandatory equipment demonstrations of response technologies under adverse conditions for operations that will occur in the Arctic Ocean.

BSEE disagrees. Under the requirements of the existing OSRP regulations and the implementing guidance contained within the PREP Guidelines, the operator must conduct equipment deployment exercises, without reference to the operating conditions, for the purposes of training, testing, or demonstrating the preparedness, material condition, and proficiency of personnel and equipment. These exercises are normally conducted under operating conditions that are conducive to achieving the deployment exercise objectives while maintaining a suitable margin of safety for all participants. BSEE does not believe that the increased risks associated with conducting exercises under adverse conditions are justified by an attendant increase in preparedness.

One commenter argued that a facility engaged in seasonal use in the Arctic will have difficulty complying with the regulatory exercise requirements, and that conducting equipment deployment drills that focus on ice intervention practices will not be of value during the open water season.

BSEE disagrees. Plan holders drilling only during the open water season have the same triennial period to comply with exercise and training requirements as all other operators. A plan holder may conduct their exercises and training when they deem most appropriate as long as they meet the regulatory requirements for the frequency of exercises. Incident management team and deployment exercises, designed to test ice intervention practices, may be done during the drilling off-season when ice is present if that is deemed a more valuable exercise. BSEE disagrees that equipment deployment drills focusing on ice intervention practices are not of value to operations during the open water season, as sea ice can be present throughout the year and would be very relevant to an early- or late-season spill response.

One commenter urges BSEE to remove the provision in § 254.90(c), under which the BSEE Regional Supervisor may require deployment of the capping stack, cap and flow system, and containment dome, and other similar subsea and surface devices and equipment and vessels, as part of announced or unannounced exercises or compliance inspections, due to the disruption it will cause to an already brief open water drilling season.

BSEE acknowledges the concern raised by this comment, and agrees that exercises of SCCE, if deemed necessary, should be conducted in a manner that minimizes disruptions to operations during the open water drilling season. BSEE will retain the provision in the rule to provide the Agency with the maximum flexibility possible to exercise its preparedness assessment and evaluation responsibilities, as necessary to demonstrate the operator's preparedness to respond during active operations. However, BSEE will ensure that SCCE deployment exercises are designed to minimize disruptions to the drilling season to the extent practicable.

One commenter recommended that any exercises directed by the Regional Supervisor should only occur after the plan holder has been notified and the particulars of the exercise have been discussed and agreed upon by all parties.

BSEE disagrees. While BSEE acknowledges the value of collaborative pre-planning in designing and holding exercises, BSEE reserves the discretion and flexibility to hold exercises in both announced and unannounced manners, as deemed necessary and appropriate, to assess and verify a plan holder's readiness and spill response preparedness. The operator's ability to execute its spill response operations with the limited notice that would be afforded in a real-word spill scenario is a critical aspect of that preparedness. BSEE will notify in advance and collaborate with plan holders in designing exercises whenever practicable when such procedures are in alignment with BSEE's exercise and overall compliance objectives.

One commenter opposed the provision for exercising equipment deployment requirements for SCCE and recommended it be removed due to the costs and operational risks involved, and the lack of specificity regarding these requirements in the regulations.

BSEE acknowledges equipment deployment exercises of SCCE are likely to be costly and may involve increased operational risks. Currently there is no recurring equipment deployment exercise requirement for SCCE outside of being directed to do so by the Regional Director or the Chief of the Oil Spill Preparedness Division of BSEE. Due to the increased costs and risks associated with this activity, BSEE intends to use this authority only when it deems it absolutely necessary to verify a plan holder's preparedness.

One commenter asserted that the provision in § 254.90(c) allowing the Regional Supervisor to direct the plan holder to deploy and operate spill response equipment or SCCE as part of an exercise or compliance inspection is contradictory to the information contained within the PREP Guidelines

and MOA OCS–08, and therefore should be revised.

BSEE disagrees. The PREP Guidelines and USCG/BSEE MOA OCS–08, *Mobile Offshore Drilling Units (MODUs),* provide additional guidance on how existing regulatory requirements are to be implemented. Any new requirements promulgated in a rulemaking would take precedence over contradictory content in the PREP Guidelines. However, it is BSEE's position that the requirements in this rulemaking and the language expressed in PREP and in the MOA are in alignment with respect to BSEE's intended posture for exercising SCCE as a capability listed in a plan holder's OSRP. BSEE views the deployment of SCCE as a demonstration of a response capability necessary to secure and mitigate the threat of a potential or actual discharge of oil. Until such time when new regulatory requirements for conducting deployment exercises of SCCE are promulgated in Part 254, BSEE will continue to implement the exercise compliance posture as it has been outlined in the PREP Guidelines.

Two commenters oppose finalizing the requirement for BSEE to direct a plan holder to mobilize and deploy equipment during an exercise because it will cause confusion over who has oversight authority to direct a response during an actual spill.

BSEE disagrees with this comment. The requirement in § 254.90(c) only applies to BSEE directing the deployment of response equipment in an exercise for the purposes of evaluating a plan holder's preparedness, and does not apply to a response during an actual spill. For any spill in the coastal zone, the USCG is the FOSC who has overall authority to direct oil removal operations. Further information regarding the respective coordination between the USCG and BSEE for both preparedness and spill response activities is found in USCG/BSEE MOA OCS–03, *Oil Discharge Planning, Preparedness and Response.* BSEE does not believe requiring the deployment of response of equipment for the purposes of an evaluation will result in confusion during an actual spill.

One commenter requested that the proposed revisions to part 254 apply to all operations on the Arctic OCS.

BSEE disagrees and this comment is beyond the scope of this rulemaking. While BSEE acknowledges that certain regulatory provisions would be beneficial for non-exploratory Arctic OCS activities, such provisions are beyond the scope of this rulemaking. BSEE will consider extending Arctic-specific provisions to other operations, such as drilling from gravel islands, or oil production activities, in a future rulemaking.

One commenter suggested the requirements for conducting exercises should be more specific regarding the timing of such exercises.

BSEE disagrees. Beyond the established frequency requirements in the regulations and in the PREP guidance, the timing of conducting planned exercises is left to the discretion of the plan holder in order to allow them to develop an integrated and effective exercise, equipment maintenance, and training cycle that meets their needs.

C. Discussion of Comments on the Initial RIA

Comments on the initial RIA generally related to the exploratory drilling scenario, cost factors used, baseline assumptions and benefits. BOEM/BSEE revised cost factors or assumptions and expanded the discussion of qualitative benefits for the final RIA. The comments received, information provided by commenters and whether changes were made in the final rule RIA is discussed herein.

Revised Assumptions

Several commenters question the assumptions about future levels of industry activity in the Arctic OCS contained in the initial RIA.

We acknowledge the commenters' concern. In accordance with recently announced changes in future Arctic exploration plans, such as Shell, ConocoPhillips and Statoil's decisions to suspend exploration activity offshore Alaska, BOEM and BSEE have revised the exploration scenario in the final RIA.[45] The scenario assumptions have been updated to reflect the relinquishment and termination of many Chukchi and Beaufort leases. BOEM and BSEE's level of expected Arctic OCS exploration activity has been maintained, however the beginning year is no longer assumed. The rulemaking exploration scenario aligns activity with numbered years instead of calendar years. The result is that the Bureaus are not estimating when exploration may begin, but rather the likely activity when it does resume. Acknowledging the temporal uncertainty of future Arctic exploration allows the public to focus on the potential compliance costs and benefits of the rule. The final RIA's activity assumptions represent an aggressive exploration scenario which presents a likely maximum of the compliance costs expected from this rule over the 10 numbered years once Arctic exploration is resumed.

The proposed rule's scenario spanned from 2015 to 2024. The final RIA scenario spans from year 1 to year 10. Activity assumptions are based upon a number of variables that are difficult to predict, including the willingness of operators to invest in conducting such operations, the availability of assets required to conduct operations, and a number of other issues. BOEM and BSEE have made these assumptions to ensure that they do not understate costs associated with the final rule. The scenario, therefore, includes 10 years with 9 years of active exploration and 50 wells drilled.

Additionally, the exploration activity scenario no longer includes an idle relief rig. During the 2015 drilling season, Shell sought to use two drilling rigs at different sites and to designate each rig as the relief for the other. Because of legal restrictions, Shell ultimately only used one rig to conduct drilling operations; the second rig remained idle during the drilling season. That rig, however, was contracted to perform drilling operations and was located at a potential second drilling site. We have concluded that, with clear regulatory requirements in place, an operator in the future is most likely to productively employ all rigs for active exploratory drilling rather than have an idle relief rig. Consistent with this fact we acknowledge the capital and operational expenditure for a second Arctic rig even though productively employed may not be a company's best use of its capital. It may prefer to explore elsewhere or deploy its capital on development projects rather than exploration. Companies are forced to employ a drilling rig for this potentially less efficient use of capital resources. Therefore, we acknowledge that it is not a cost free decision for operators and lessees.

BOEM and BSEE have adopted what we view to be conservative (*i.e.,* high side) projections of the Arctic OCS activities that can be reasonably anticipated. We assume for purposes of this analysis that three operators will be present on the Arctic OCS over the 10-year analysis period, with one operator conducting exploratory drilling beginning in year two and two additional operators commencing exploratory drilling in year 4. These assumptions reflect potential activity based on expectation for future Arctic

[45] Shell updates on Alaska exploration, September 28, 2015 press release, *http://www.shell.com/global/aboutshell/media/news-and-media-releases/2015/shell-updates-on-alaska-exploration.html.*

leasing. For the total number of exploratory wells on the Arctic OCS, we assume four wells in year 2 and year 3 and six wells from year 4 through year 10. Additionally, the final RIA assumes that: (1) The number of wells drilled and the number of APDs submitted to BSEE will be equal for each year of the analysis period; (2) each operator will submit to BOEM an EP in the year prior to exploratory drilling; and (3) an IOP and OSRP will be submitted by each operator in each year prior to drilling.

Two commenters question the difference between the initial RIA and the NPRM cost-effectiveness analysis as to the number of operating rigs. The commenter cites the initial RIA as assuming one rig operating in 2015–2016, two for 2017, and four rigs operating from 2018–2024, and the NPRM cost-effectiveness analysis assumes two rigs operating for 2015–2017 and then four rigs operating from 2018–2024. The commenter questioned the difference and concludes that the assumptions would result in a ten-year cost of $174 million based on the initial RIA, while using the number of operating rigs per year set forth in the NPRM scenario would result in a ten-year cost of $204 million. However, the commenter points to the average annual cost used in the initial RIA as being $19.2 million, which does not match the assumptions outlined in either document.

BOEM and BSEE are aware of the difference in the relief rig assumptions between the initial RIA and the NPRM cost effectiveness analysis. We decided to use assumptions in the initial RIA that would present the likely maximum level of compliance costs, which included assuming the presence of a dedicated standby rig for years 2015–2016. However, the final RIA assumptions render this difference moot. As described above, the scenario for future Arctic exploratory drilling operations has been revised. The rig counts throughout the RIA were revised for consistency. BOEM and BSEE no longer assume that operators will have an idle relief rig and instead assume that operators will have all rigs actively engaging in exploratory drilling. The revised Arctic exploratory drilling scenario has zero rigs drilling in year 1 (no operators actively drilling), two rigs drilling in years 2 and 3 (assuming one operator), and four rigs drilling during years 4 to 10 (assuming three operators).

One commenter questioned the assumption related to industry sharing oil spill response assets and believes costs should have been calculated on the basis of a single industry participant operating in the region. The commenter noted the costs were based on an assumption of modest growth in the number of operators in the region during the next decade, but if fewer operators seek to operate on the Arctic OCS, there will also be fewer opportunities for operators to enter into contractual agreements to share relief rigs and other oil spill response equipment. The commenter stated that, if this occurs, operators will need to furnish their own relief rigs and associated infrastructure, thereby driving up operating costs.

The revised assumptions used for the final RIA include years in which one operator is operating in the Arctic and other years in which multiple operators are engaging in Arctic exploration and can share resources. Annual costs show the range of compliance costs from years 2 and 3 when one operator must bear all of the costs to the later years when operators can engage in resource sharing. Even in the beginning of the scenario when a single entity operates, we assume that operator has two rigs with no standby relief rig, as all operators are assumed to actively engage all rigs in exploratory drilling. Regardless of the number of operators, whether it be one or more than one, additional operating rigs are assumed to be used even with sharing of resources. With three operators in year 4, the analysis assumes that there are four operating rigs. BOEM and BSEE's compliance cost calculations consider the vessels which can be shared between operators (*e.g.,* oil spill response vessels) and assume the one operator must pay for all of these services in years 2 and 3, but these costs are shared between operators in the later years. If we followed the commenter's assumption of only one operator, per-well costs would be higher, but the total compliance costs would be an underestimate of what they would be in the presence of multiple operators. The approach used in the final RIA analysis demonstrates the higher per well costs in the early years with only one operator, but also recognizes that resources can be shared in later years if additional operators enter the region.

One commenter questioned the Bureaus' assumption that only one operator will be operating through 2017, but that relief rigs would be cross-assigned between different operators to satisfy the requirement, meaning each operator's primary rig would be utilized by the other operator as a relief rig in the case of a well control incident. The commenter recommended the cost analysis for this time period should not be based on cross assignment between operators, as the Bureaus have provided no basis on which to assume an operator would bring more than one rig to the theater if not for the proposed relief rig requirement.

We no longer assume that an operator would bring more than one rig solely to serve as a standby relief rig. Instead, it is assumed that, during years 2 and 3 with one operator, the operator will have two operating rigs and will designate each rig as relief rig for the other. While it is possible that an operator may have only wanted to drill one well in the Arctic (thus not bringing a second rig if not for the relief rig requirement), we believe that, from an economic perspective, regardless of the relief rig requirement, it would be prudent for an operator to bring two rigs to the region. Given the large fixed costs of drilling in the Arctic (regardless of this regulation's new requirements), the marginal cost of a second rig would likely justify the operator to bring two rigs, in that they could share common support vessels, etc. The rig count scenario was revised for consistency in the final RIA.

One commenter questioned the initial RIA assumptions that two IOPs will be submitted in 2015, however only one EP will be submitted. The commenter requested that the Bureaus clarify under what circumstances more IOPs than EPs would be submitted in any given year, as the IOP requirement is tied to submittal of an EP. The commenter further questioned the initial RIA assumptions in Exhibit 3 showing three operators working on the Arctic OCS from 2018 to 2024, while the numbers of IOPs, EPs, and OSRPs are not in line with that number of operators.

BOEM and BSEE agree that the number of IOPs and EPs should be the same. The final RIA revises the IOP and EP assumptions from the proposed rule and initial RIA so that a single EP and single IOP per operator are submitted in the year prior to exploratory drilling.

Overestimated Costs

Several commenters assert that the cost assumptions in the initial RIA are significantly overestimated and many of the costs of the finalized regulatory provisions should be included as baseline costs. One commenter expressed concern that the initial RIA overstated the costs of the proposed rule by assigning existing baseline costs that operators already include in their budgets as incremental costs. The commenter noted that many of the regulatory provisions in this final rule codify existing industry practices or incorporate existing requirements imposed by the Department as a condition of plan approval, through an

NTL or as BAST) methods under § 250.107.

After reviewing comments, BOEM and BSEE have determined some of the costs identified as new regulatory compliance costs in the initial RIA are, instead, baseline costs. Costs are considered baseline if they are attributable to existing regulatory requirements, industry standards, and operator best practices. OMB's Circular A–4 (''Regulatory Analysis'') directs that the baseline should be ''the best assessment of the way the world would look absent the proposed action.'' BOEM and BSEE have broad authority under existing regulations to impose reasonable conditions on exploration plan approvals and drilling permits. Thus, the final RIA excludes from new compliance costs the activities or capital investments that existing regulations may require, as well as impacts resulting from the incorporation of industry standards with which the industry voluntarily complies.

The two provisions that are codified in this rulemaking and considered in the regulatory baseline are Additional Requirements for Securing Wells (§ 250.720) and Real-time Monitoring Requirements (§ 250.452). To supplement the analysis, we include a discussion of the baseline assumptions within the text of the final RIA and acknowledge the compliance cost for these two baseline provisions in the RIA appendix.

Compliance Cost Estimates

BOEM and BSEE considered all comments and revised the cost estimates for some provisions based on information provided in comments. Costs provided in comments were considered and greatly influenced the cost estimates used in the final RIA.

As mentioned above, the biggest change in the compliance cost of the rule relates to the characterization of costs, as BOEM and BSEE concluded that industry's existing practices and BOEM's and BSEE's current regulations would be used as the baseline for our analysis. To supplement the analysis, we included a discussion of the baseline costs within the text of the final RIA, and in developing the new compliance costs and estimates of the baseline cost, BOEM and BSEE seriously considered, and in many cases used, cost estimates provided by commenters that could be validated or were deemed reasonable.

Several commenters argue that the costs of the initial RIA were significantly underestimated and that the rule will result in a negative impact to America's economy and energy security by inhibiting oil and gas development on the Arctic OCS. One commenter asserted that the approximately $1 billion cost to industry estimated in the initial RIA over the 10 year assessment period fails to address the impacts of shortening the effective drilling season, driven primarily by the same-season relief well requirement. The commenter also argued the RIA uses assumed spread rates for drilling and emergency response facilities that are far lower than demonstrated by industry experience. The commenter asserted that the Bureaus' estimated costs in the initial RIA are drastically low, sometimes by several orders of magnitude, and that the cost to industry is $10–20 billion higher over the 10-year period. BOEM and BSEE generally disagree.

BOEM and BSEE considered these comments. The cost estimates provided comments influenced the compliance cost estimates for several provisions in the final RIA. In developing the new compliance costs and estimates of the baseline cost, BOEM and BSEE closely considered and in many cases used revised cost estimates provided in comments. The final RIA includes revised cost assumptions for each provision.

Regarding the assertion that our regulation of offshore oil and gas production in the Arctic will inhibit a large amount of economic activity, including preventing the creation of many new jobs, we disagree. Industry interest in potential development in the Arctic OCS region of Alaska is largely driven by the price of oil and gas and the challenging and harsh conditions in the area, as evidenced by recent departures from the area by Shell and Statoil. As a result, the Arctic OSC region of Alaska has not previously relied on the type of offshore drilling regulated by this final rule for economic development or well-being. The OCSLA states that the policy of the U.S. is to both make the OCS available for production and development as well as to ensure that operations are conducted safely. Lessees, particularly in the Arctic, obtain OCS leases and pursue exploration with a full understanding of this dynamic. This rulemaking reflects the Bureaus' reasonable and appropriate fulfillment of their multifaceted OCSLA mandates.

In addition, the final regulations could bring potential benefits to the local economy and cultural traditions from reduced risk of oil spills. A catastrophic oil spill would have negative economic impacts far beyond the offshore oil and gas industry. A catastrophic oil spill could disrupt subsistence practices, such as whaling, on which Native Alaskans rely for food and for their cultural preservation.

One commenter asserted that the initial RIA incorrectly estimates the daily per-rig operating cost at $2 million because it fails to take into account that rigs and vessels contracted for Arctic exploration are contracted on an annual basis. The commenter further states that, by considering the operating costs for a single day via day rates based on 365 days per year of utilization, the Bureaus have understated significantly the cost of a drilling day lost due to regulatory requirements or constraints. The commenter recommended that the cost should be captured in a weighted daily estimate of operating cost tied to the shortened Arctic operating season. The commenter noted that, based on an estimated 100 drilling days available in the Chukchi Sea, this results in an effective daily operating cost of $7.5 million per day per rig when the full cost of 'ownership' is taken into account. Due to the significant fixed cost burden, the commenter asserted that the cost of a day spent not operating can be estimated at 80 percent of the operating rate, or $6 million per rig per day.

BOEM and BSEE have addressed this comment in the final RIA by adjusting the daily rig operating costs to $3.97 million, which assumes the operating rig must be contracted for the entire year and supporting vessels for part of the year. To address lost drilling days, the compliance cost of the ''shoulder season'' [46] is also estimated. It is assumed that the shoulder season requirement will shorten the drilling season by 34 days, out of the estimated 116-day drilling season. This 29 percent reduction in drilling days is used to estimate that 29 percent of the annual cost of the drilling rig is lost due to this provision. There are also savings realized during the 34 days from support vessels demobilizing 34 days earlier. BOEM and BSEE also note that operators may still undertake productive activities on wells during the shoulder season. However, to provide maximum estimate of potential cost of the shoulder season, these benefits are not considered in the estimated cost. The final RIA estimates the annual shoulder season costs as $84.42 million

[46] The shoulder season is the period of time operators may not drill or work below the surface casing, and its length is dependent on an operator's ability to demonstrate the capability of the relief rig to arrive on site, drill a relief well, kill and abandon the original well and abandon the relief well prior to expected seasonal ice encroachment at the drill site.

in years 2 and 3 and $177.95 million per year in years 4 to 10.

One commenter disagrees with the initial RIA's assumption that the operating season on the Arctic OCS is 138 days long and asserted the Bureaus have exaggerated the season length and incorrectly spread costs across a greater number of days, resulting in the overall cost impact being incorrectly reduced. The commenter asserted that current regulatory constraints make July 1 to October 31 the highest potential estimate for season length (totaling 123 days), while ice data collected over the last 10 years would indicate an average season length of approximately 100 days. The commenter questioned whether the Bureaus have either assumed operators will have access prior to July 1, which is prohibited by current USFWS regulations, or extended the season past October 31, which is not supported by historical ice data.

BOEM and BSEE agree and have used assumptions that reflect a drilling season reduced to 82 days long. BOEM and BSEE estimate the ice-free season to be 116 days long (from July 7 through October 31) and subtract 34 days for the baseline shoulder season.

Two commenters questioned the cost of familiarization with the requirements of this rulemaking. One commenter asserted that the time estimated in the initial RIA for industry staff to generate the information was understated and allocated incorrectly to managerial time, when the work would be done by mid and senior level engineers. Another commenter stated that their experience with implementing rule packages for operations necessitates an initial time commitment involving a number of people across a number of teams, resulting in a time commitment 50 times as large as that assumed in the initial RIA. The commenter added that there would be an ongoing need to onboard staff and contractors, resulting in 250 hours of labor per year for review in subsequent years.

BOEM and BSEE agree in part. In the final RIA we revised the estimated staff times required by industry for familiarization with the regulation. It is assumed for each operator that a senior engineer will spend 250 hours to review the new regulation. It is also assumed that each operator will spend 120 hours per year assuring new personnel's familiarity with the rule to prepare for the next drilling season.

Several commenters question the benefits analysis of the initial RIA, and many specifically cite to benefits being calculated based on the conditional assumption that a catastrophic oil spill will occur on the Arctic OCS in the next ten years. Commenters assert this assumption is at odds with the broadly acknowledged understanding, as stated in the NPRM, that the probability of such an event is extremely low. One of the commenters noted the initial RIA calculated the benefits of the regulatory action by assuming costs based on the clean-up of the 2010 Macondo spill in the Gulf of Mexico, but that the estimated oil released at Macondo was twice the ''worst-case discharge'' projections for any Chukchi Sea oil spill. Three of the commenters question the initial RIA benefits analysis as being inconsistent with the February 2015 Chukchi Sea Lease Sale 193 Supplemental Environmental Impact Statement. They suggest that the final RIA should align to the less than one percent chance of a large oil spill during exploration of the Arctic OCS.

BOEM and BSEE have determined the benefits of the final rule justify the costs when qualitative factors are considered. The potential impact and cost of an Arctic OCS oil spill is substantial. This rule's spill control mechanisms provide significant potential benefits through avoided spill costs. This justification relies on both qualitative and quantitative analysis. BOEM and BSEE acknowledge previous studies which have found the estimated probability of a catastrophic oil spill to be very low; the final RIA provides frequency estimates for large oil spills, but it is usually true of catastrophic risks that society deems it worthwhile to defend against them or be prepared to remedy them despite the low probability of the event. The American public greatly values the Arctic. It is viewed as a pristine, unspoiled environment. With this in mind, a catastrophic oil spill would have severe impacts and it is meaningful to examine the highly unlikely scenario of a catastrophic oil spill.

Given both the low probability and high consequence nature of a catastrophic oil spill, and after review of public comments, BOEM and BSEE did not conduct a break-even analysis on the provisions in this final rule. Such an analysis could misrepresent both the underlying risk of a spill and the magnitude of costs which could result. The Initial RIA included a break-even analysis which was conditional on a catastrophic oil spill occurring. This analysis was removed, in part, as a response to comments which suggested that such an analysis was flawed and implied that a catastrophic oil spill would occur in the Arctic without the new regulations. Instead, the RIA provides estimates of the probability of a catastrophic oil spill and the range of potential costs of various size catastrophic oil spills. If the regulatory provisions were able to prevent a catastrophic oil spill, the benefits of the avoided spill costs have the potential to far exceed the rulemaking costs. In addition, the RIA discusses the spill control mechanisms in the rule which have the ability to limit spill costs and monetizes the potential avoided costs from each provision. Together, this information identifies the substantial benefits of the rule in avoiding the costs of a catastrophic oil spill while acknowledging the underlying low probability of a spill.

BOEM and BSEE analyzed the specific provisions of this regulation designed to reduce the length of a catastrophic oil spill. The analysis focuses on the conditional state where a spill is assumed to occur within the 10-year scenario. BOEM and BSEE used historical data on oil spills to estimate the potential costs that would result from spills of various durations in the Arctic OCS region. BOEM and BSEE then used the final rule costs and the avoided damages of potential spills to estimate the possible rulemaking benefits. The initial RIA expressed the break-even analysis results in terms of the number of days of spilled oil that would need to be avoided for specific provisions of the regulation to be cost-beneficial. The final RIA includes an expanded discussion of potential avoided spill costs by spill control mechanism and the qualitative benefits of the regulation.

One commenter requested the final RIA strengthen its ''Benefits'' analysis by estimating the safety benefits, and not just the environmental benefits, of the proposed rule. The commenter noted that, if major oil spills are prevented by the rulemaking, there clearly would be safety benefits as well.

In response to comments received about the safety benefits, BOEM and BSEE expanded their discussion of this topic in the benefits section of the RIA, including a discussion on the importance of codifying existing industry standards and practices. These benefits result from the rule's requirements that reduce the probability of a catastrophic spill from a well control event and reduce the duration of a spill should one occur. Both of these reductions will increase safety in addition to their environmental benefits. The RIA considers the benefits of increased safety by considering the avoided costs from human fatalities and injuries that could occur during a catastrophic well control event and spill.

IOP Cost Estimates (§ 550.204)

One commenter questioned the initial RIA calculation of staff time required to develop the IOP for submission, and asserted the time is underestimated by almost a factor of 40. The commenter estimates the costs of this provision to be $793,212 annually, instead of the $125,167 annual cost cited in the initial RIA.

In response to this comment, BOEM revised the estimate of hours needed to prepare an IOP. The number of hours mid-level engineers spend to compile and include the required information in the IOP is revised to be 2,880 hours, resulting in a cost to industry of $281,721 per IOP, which is an increase from the initial RIA.

EP Cost Estimates (§ 550.220)

One commenter stated the initial RIA underestimates the amount of time required to develop the additional information required for submission of the EP by more than a factor of 20. The commenter assumed that 1,050 hours of industry staff time and 144 hours of agency staff time will be required, resulting in total average annual costs of $215,815. The initial RIA assumed 45 hours of industry staff time and 144 hours of agency staff time, resulting in average annual costs of $28,702. The commenter contends that development of the EP is a time intensive effort requiring input from a wide range of teams across the company to fully incorporate all of the information required by regulation.

BOEM finds the commenter's estimate reasonable for compiling and submitting the required information from different expertise areas. The required EP information includes descriptions of different operator emergency and contingency plans, information on suitability for Arctic OCS conditions, ice and weather management, SCCE capabilities, deployment of a relief rig, resource sharing, and anticipated end-of-season dates. The industry staff time assumptions in the final RIA match the estimate provided in this comment. Mid-level engineers are estimated to spend 1,050 hours compiling the required information for the EP. Multiplied by the median hourly compensation rate for mid-level engineers, the estimated industry cost is $102,711 per EP. The cost to BOEM remains the same at $10,898 per EP.

Incident Reporting Cost Estimates (§ 250.188)

One commenter identifies two issues with the costs and burden associated with the incident reporting provisions of proposed § 250.188. First, the commenter noted the difference between the initial RIA accounting for one rig in 2015 and 2016 and the NPRM analysis that accounted for two rigs each of these years. From this, the commenter concludes that there would be a doubled cost for 2015 and 2016 if the analysis in the final RIA were updated to align with the assumptions of the NPRM analysis. Second, the commenter questioned the number of hours of staff work required to compile and document the required information. Based on the commenter's own previous experience during the 2012 season, the commenter estimated that instead of 5.5 hours of mid-level engineer time as a cost to industry, each incident would require 50 hours. The commenter supports the estimate by stating that a multidisciplinary team would work together to gather the necessary information, and the time estimates should account for the time required to review and prepare the submission by a senior level engineer, which is estimated to be 50 percent of the time required to gather the data, resulting in an additional 25 hours of cost. The commenter noted that for the cost to the agency, the relationship of 50 percent of the time required to gather the data being required to review the submission was maintained, resulting in 25 hours of review time for the agency.

In the final RIA, the assumptions regarding staff time are revised for this provision. It is assumed that incidents having new reporting requirements the final rule will occur two times a year for each rig. Industry mid-level engineers will spend 50 hours and industry senior engineers will spend 25 hours on reporting requirements for each incident. It is assumed that a BSEE senior engineer will spend 25 hours reviewing each submittal.

Pollution Prevention (§ 250.300)

One commenter argued the initial RIA did not consider the operational and logistical burdens and costs associated with zero discharge operations for petroleum-based muds and cuttings. The commenter also argued the initial RIA did not account for costs associated with the authority of BSEE's Regional Supervisor to direct operators to capture water-based muds and cuttings, which will require operators to take into account that BSEE may drastically modify operations without warning, and the operator must plan accordingly. The commenter stated the initial RIA also did not account for any costs associated with the modification of rigs to handle a collection system, containers to collect and transport the muds and cuttings, vessels to transport the resulting volumes, or costs for the disposal of the mud and cuttings. The commenter asserted that an analysis of costs associated with Shell's 2012 Beaufort campaign, as well as updated plans based on what was learned from that campaign, demonstrate one-time costs required to prepare rigs and support vessels for a collection system. The commenter also identified additional operating costs for the rig system and for the collection, storage, and transport systems, which it states should all be included in compliance cost estimate for this provision.

The commenter disagrees with the initial RIA assumption that a skilled laborer on the rig crew and an industry senior engineer would spend, respectively, 60 and 8 hours annually to transport and dispose of mud and cuttings, resulting in an annual labor cost of $4,245 ((60 hours × $56.86) + (8 hours × $104.22)) per rig. The commenter proposes an alternative cost estimate for this provision as follows: $10 million to modify an existing rig and equipment for zero discharge operations; $2 million (annual cost per rig) to operate additional equipment on the rig; $3 million in upfront logistics costs per rig supported; and $14.5 million in annual logistics costs for the transport and disposal of waste. Taking into consideration the assumptions in the initial RIA Exhibit 3, the total cost of this provision would be $52 million in one-time costs to modify each rig and each rig's supporting logistic assets, and $561 million in total operating costs over 10 years, resulting in a total 10 year cost of $613 million.

BOEM and BSEE considered the comments received on the pollution prevention requirements and updated portions of the RIA accordingly. Based on other comments received and additional analysis conducted by the Bureaus, the final RIA assumes that the requirement to capture all petroleum-based mud and cuttings under this provision is in the baseline. The capture of petroleum-based mud and cuttings is an established industry practice and is required separately by EPA as part of the applicable NPDES permits. As this requirement is imposed separately by EPA, BOEM and BSEE do not include a cost for the capture of petroleum-based mud and cuttings as a cost of the rule.

BOEM and BSEE do consider the Regional Supervisor's discretion to require the capture of water-based muds and cuttings to result in costs attributable to this rule and have added an estimate of these costs to the final RIA. These costs are not considered as part of the baseline because the capture

was not a condition of either the 2012 or 2015 exploration plans. Rather, Shell voluntarily negotiated with whaling captains and agreed to capture water-based muds and cuttings as part of its 2012 Beaufort Sea exploration program. We note that the final rule does not explicitly require the capture of water-based muds and cuttings and instead gives the Regional Supervisor discretionary authority to require it based on various factors, including the protection of marine mammals, fish, and their habitat, and negative impacts to subsistence activities. Accordingly, these estimated costs in the final RIA may be overstated because of the possibility that capture will not be required. However, we have determined to include these compliance costs in the final RIA because, in addition to the fact that the capture of water-based muds and cuttings was not a condition of the 2012 or 2015 exploration programs, the likely proximity of exploration drilling in the Beaufort Sea to bowhead whale migration corridors and/or subsistence activities makes it more likely that the Regional Supervisor would exercise authority requiring the capture of water-based muds and cuttings in the Beaufort Sea. The annual cost is estimated to include a capital cost of $13.0 million to install capture equipment. The annual cost of operating the equipment disposing of cuttings is estimated to be $16.5 million. The average annual cost of this provision is estimated to be $18.1 million.

Mudline Cellars (Formerly § 250.402)

One commenter stated the cost of complying with the requirements proposed at § 250.402(c) will result in a total cost of $4 billion over the ten years, compared to the Bureaus' estimated cost of $240 million. The commenter based its estimated costs on the assumptions in Exhibit 3 of the initial RIA, which assume 48 wells will be drilled during the ten-year period. The commenter estimated the cost per season for a two-rig program to be approximately $1.5 billion, leading to daily operating rig costs (based on a 100 day drilling season) of $7.5 million and lost rig day costs of $6 million. The commenter calculated that, based on the assumption of 1.5 days of additional lost time per well due to this provision, the cost is $9 million per well (1.5 days at a lost rig day rate of $6 million), which is three times larger than the initial RIA estimate of $2 million per well. The commenter argued that assuming a cost of $6 million per operating day results in an additional estimated cost of $9 million per well, and $432 million across the 48 wells assumed to be drilled in the ten-year period. The commenter further adds that inclusion of the costs for each rig to buy and maintain a dedicated mudline cellar bit adds $298 million to the cost across the 10-year program. Another commenter stated that the requirement for securing a well has long-required the use of well cellars and proper temporary abandonment of Arctic wells. The commenter asserted this is not a new requirement and should be included in the baseline costs.

BOEM and BSEE agree that the requirements under the former § 250.402 (finalized in the Well Control Rule as § 250.720), including mudline cellars, are a long-standing industry practice and are required by existing regulations (§ 250.738) for Arctic OCS MODU drilling operations in ice scour areas. Accordingly, we have included the costs of the mudline cellars in the final RIA's baseline cost estimate. BOEM and BSEE have adjusted the estimated compliance cost based on information received in comments and the number of drilling days required to drill or construct a mudline cellar. We assume that the mudline cellar will take 10 days to drill or construct, based on actual time required during the 2015 exploration drilling program. We further updated the average daily drilling cost. These calculations resulted in a mudline cellar drilling cost of approximately $37,000,000 per well.

The mudline cellar requirement imposes a capital cost per drilling rig (for the mudline well cellar drill bit) and a maintenance cost (for upkeep of the drill bit). These costs were not fully considered in the initial RIA but are included in the final RIA.

Real-Time Monitoring Requirements (§ 250.452)

One comment questioned the assumption of the initial RIA that there is an incremental cost of $6 million per year, per rig for RTM requirements. The comment suggests that, because these measures were employed by Shell in 2012, there is no incremental cost to that operator. BOEM and BSEE agree and consider RTM costs to be part of the regulatory baseline. RTM was required as part of the approvals for the 2012 and 2015 Shell EPs, and the use of RTM has become a standard practice by industry on the Arctic OCS. Additionally, RTM provisions are codified in the final BSEE BOP/Well Control rule at § 250.724. While RTM is considered a baseline cost, BOEM and BSEE acknowledge there may be instances when RTM could be required under § 250.452 but not under § 250.724. Section 250.724 requires RTM when conducting well operations with a subsea BOP, with a surface BOP on a floating facility, or when operating in an HPHT environment. Arctic exploratory drilling may be conducted from grounded platforms such as a jack-up rig that do not utilize a subsea BOP. In these cases RTM would be required and could be considered a compliance cost assigned to § 250.452. However, as a general matter, the use of real-time monitoring has become an industry standard in the context of challenging conditions such as deepwater or HPHT wells (as reflected in the Well Control Rule) and Arctic OCS exploratory drilling (as reflected here and in the 2012 and 2015 plans). Accordingly, based on the requirements of the Well Control Rule and standard industry practices in challenging Arctic conditions, BOEM and BSEE have concluded that costs associated with maintaining real-time monitoring capabilities are properly considered baseline costs.

One commenter suggests that the RTM compliance costs were underestimated. They suggest that the cost to operate a monitoring system is approximately $10,000 per day, compared to the $5,000 per day used in the initial RIA. They suggest that, in a 100-day season, the system would be operated for approximately 144 days, with 30 days prior to the season utilized to get systems up and running and then two weeks following the season to close down. They further suggest that the initial system would cost $400,000 per operator with an additional $200,000 every three years to replace or update monitoring system components.

In the baseline cost analysis, BOEM and BSEE assume the RTM systems would be operated for 126 days per year, which consists of the 82 day drilling season (116 days in the season less the 34 day shoulder season), 30 days for set-up, and 14 days for take-down. We have kept the $5,000 average daily cost consistent with information received as part of the BSEE Well Control Rule. The initial system cost and refurbishing cost were revised based on this comment. A $400,000 initial system cost and a $200,000 refurbishing cost, incurred every three years, are included in the baseline final RIA cost estimate.

APD Cost (§ 250.470)

One commenter expressed concern about the incorporation of API RP 2N Third Edition as part of an operators' APD submittal. The commenter mentions that the RP explicitly states its inapplicability to MODUs, and concludes that the Bureaus' attempt to estimate the cost of incorporating an

inapplicable standard as required under this provision results in undefinable costs, given the variety of issues raised by such a requirement. The commenter estimated the increased average annual costs to be $9,818, which assumes 20 hours of industry staff time and 10 hours of BSEE staff time.

BOEM and BSEE have revised the cost assumptions in response to this comment. The final RIA assumes an industry mid-level engineer will spend 20 hours on the documentation associated with the provision, which results in an annual cost of $1,956 per rig. It is assumed a senior BSEE engineer will spend 10 hours reviewing submittals associated with the requirement, for a cost of $979 per rig. With these assumptions, the average annual cost of this provision is estimated to be $10,273.

Source Control and Containment Cost (§ 250.471)

Two commenters recommend that the initial RIA's cost estimates of $31 million per year for SCCE, including a capping stack, cap-and-flow system, and containment dome, should be included in the baseline because this equipment has been required for OCS operations since 2010, pursuant to NTL 2010–N10 and Shell's 2012 EP. One of the commenters requested that, if SCCE costs are considered new regulatory compliance costs, then the capital and operating costs for each piece of SCCE should be explained.

BOEM and BSEE disagree that the costs are part of the baseline and have explained the cost assumptions in greater detail in the final RIA. The SCCE capital cost, in addition to the costs of deployment and testing of this equipment, is a compliance cost of the rule because the requirement to maintain SCCE is being formally codified in the regulations. The SCCE costs are summarized in the final RIA and total $681.9 million over 10 years (3 percent discounting).

One commenter stated that the costs for the SCCE requirements are significantly underestimated and that they should be $315 million to $685 million higher, over the ten-year period, than the costs associated with the SCCE requirements as presented in the initial RIA. The commenter asserted that the initial RIA incorrectly assumed no cost associated with the existing SCCE system by only including the cost for the purchase of a second system in 2018. The existing system is the result of what the comment states are extra-regulatory conditional permit requirements, and as such the $270 million used in 2018 was also utilized in 2015 to recognize the cost already incurred by the industry. Furthermore, the commenter states that its experience indicates that BSEE has substantially underestimated the annual operating costs of the system, accounting for only $1.2 million in operating costs per year. The commenter argued that all costs evaluated in the initial RIA assumed a continued WCD of 25,000 barrels per day as used in the approved Shell Chukchi OSRP. The commenter stated that if prospects with larger estimated WCDs are evaluated, the costs for the development and operation of the SCCE systems will scale, at minimum, linearly from the costs that are currently included, and the commenter recommended this increased cost should be incorporated into the analysis. The commenter also asserted that the cost for an annual test or exercise of the system, which would involve a full deployment of the SCCE, is underrepresented in the initial RIA. The commenter suggests that, based on current costs and experience from a 2015 deployment test, an annual test would cost an estimated $5.9 million per year per system.

BOEM and BSEE have revised the cost estimates for the SCCE testing requirements based on information received in comments and adopted the central SCCE capital scenario from the initial RIA. The central SCCE scenario assumes that one company purchases SCCE for its own use and the other two operators share SCCE. The calculation of the volume of oil under a WCD scenario varies from site to site. This information is required as part of the OSRP for each facility under § 254.47. BOEM and BSEE do not include additional costs for revised SCCE in the event that larger WCD scenarios are developed for other prospects, as these costs would be too speculative to estimate at this time. The final RIA estimates the average annual deployment and testing cost to be $22,117,333.

Relief Rig Requirements (§ 250.472)

Two commenters recommend that the $0.55 billion relief rig costs should be removed from the incremental analysis and be included in the baseline because the Bureaus have previously imposed the requirement that Arctic OCS exploration operators have a relief rig. One of the commenters noted that the costs of the standby relief rigs should not be included because operators can plan simultaneous exploration operations using two or more drilling rigs where no drilling rig would be idle on stand-by. The commenter further noted that two or more operators drilling in the Arctic at the same time could agree to share relief rig services through a mutual aid agreement, whereby no drilling rig would be idle on stand-by. The commenter concludes there is no incremental cost for a stand-by relief rig in either case, because the rigs are actively drilling wells and included in the baseline economics, and would only be called up in an emergency to provide relief rig services.

BOEM and BSEE have continued to assign the compliance cost of the relief rig and shoulder season to the rule. However, the revised activity assumptions in the final RIA exclude the presence of an idle standby relief rig. Instead of an idle standby relief rig, it is assumed that the single operator in years 2 and 3 would operate two rigs and designate each rig as a relief rig for the other. Because the exploration activity scenario no longer includes an idle relief rig, no costs are associated with this provision. BOEM and BSEE maintain that the requirement that a relief well be drilled before seasonal ice encroachment is a compliance cost of the rule. The compliance cost for the shortening of the drilling season necessitated by these requirements is estimated to be $84.4 million per year in years 2 and 3 and $177.9 million per year in years 4 to 10.

One commenter suggests that BSEE's baseline economic modeling should be based on OCS lease operators being able to drill a single well per season per rig through 2017. The commenter further suggests the realization of a multiple-well drilling season for any single drilling unit is not likely, given the seasonal restrictions, requirement for a mud line cellar, and time required to drill a relief well.

BOEM and BSEE disagree that a multiple-well drilling season is not likely. However, we do agree, considering Shell's 2015 announcement, that the number of wells per season should be revised. Accordingly, beginning in year 2 we have revised the assumptions for the number of wells drilled per season to have a maximum of two wells per rig. The initial RIA assumed four wells for one rig in 2016, and the final RIA maintains the assumptions of four wells for two rigs in years 2 and 3 and six wells for 4 rigs from years 4 to 10. By assuming that two wells per season can be drilled, we are potentially assuming a higher level of activity and thus ensuring that we are not underestimating the costs of the regulation. We considered comments on the number of exploratory wells assumed in the analysis, and upon careful consideration have determined the scenario used in the final RIA

reflects a reasonable estimate for the number of wells over the 10 year period to avoid underestimating the regulatory costs.

One commenter recommended any cost-benefit analysis of this rule package should account for the erosion to an operator's portfolio of lease holdings caused by lost drilling days resulting from the requirement for a same season relief well. The commenter asserted the regulations would make it difficult, and in many cases impossible, to complete one well in a single season and that the fewer days an operator has during the open-water season to explore its lease, the greater the number of its leases that will expire before they can be evaluated. The commenter points to the NPC Arctic Potential Study, where it is noted that the U.S. lease system is development based, and to retain a lease, the operator must have gained enough information to be able to move into the commercial development phase by the end of the 10-year primary term for an OCS lease. The short drilling season, it was argued, could make this determination practically impossible to achieve within the 10-year term when the drilling of several wells may be required to enable appraisal of a field.

BOEM and BSEE have reexamined, carefully considered and developed new estimates of the number of lost drilling days resulting from the requirements of the final rule, and have derived the effect of these lost drilling days in terms of their cost to operators. It is assumed that the relief rig requirement would shorten the drilling season by 34 days, out of the estimated 116 day drilling season. This 29 percent reduction in drilling days is used to estimate that 29 percent of the annual costs of the drilling rig is lost due to this provision. There are also savings realized during the 34 days from support vessels demobilizing earlier and other beneficial activities that can be pursued during that time, however these benefits were not incorporated into the cost estimates. The final RIA estimates the annual shoulder season costs as $84.42 million per year in years 2 and 3 and $177.95 million per year in years 4 to 10.

With regard to the NPC Arctic Potential Study, as discussed in Section IV.B.1. *General Comments,* BOEM and BSEE subject matter experts participated in the development of this study and have utilized, where appropriate, knowledge gained from its development. BOEM and BSEE recognize the NPC Arctic Potential Study as a valuable comprehensive study that considers the research and technology opportunities that exist for the prudent development of U.S. Arctic oil and gas resources. There are, however, a number of statements in the NPC Arctic Potential Study BOEM and BSEE found to be without support. For example, it suggested that there were currently available technologies, other than a relief well, that would kill and permanently plug an out-of-control well. BSEE and BOEM are aware of no such technology. In addition, the NPC Arctic Potential Study is only one of the resources that our regulatory experts considered in achieving our goal of developing regulations to ensure the safe and responsible development of petroleum resources on the Arctic OCS.

One commenter argued that the cost per year of a relief rig, and number of years for inclusion of the cost of the relief rig, is overestimated. The initial RIA utilized a methodology to calculate the cost of a relief rig that took the assumed day rate cost of a rig at $2 million per day and multiplied that by the number of days in a season at 138 days to arrive at a total of $276 million for a season. The commenter suggests that this methodology overstates the cost that would be associated with a rig that was being held on stand-by as a true relief rig at a location such as Dutch Harbor. The commenter cites an analysis performed by ENVIRON which estimated a cost of approximately $212 million per season based on publicly available data sources and the requirement of a rig, tugs to transport the rig, and a support vessel on stand-by (ENVIRON International Corporation. Arctic Regulations Benefit Cost Analysis. 2014. p. 9).

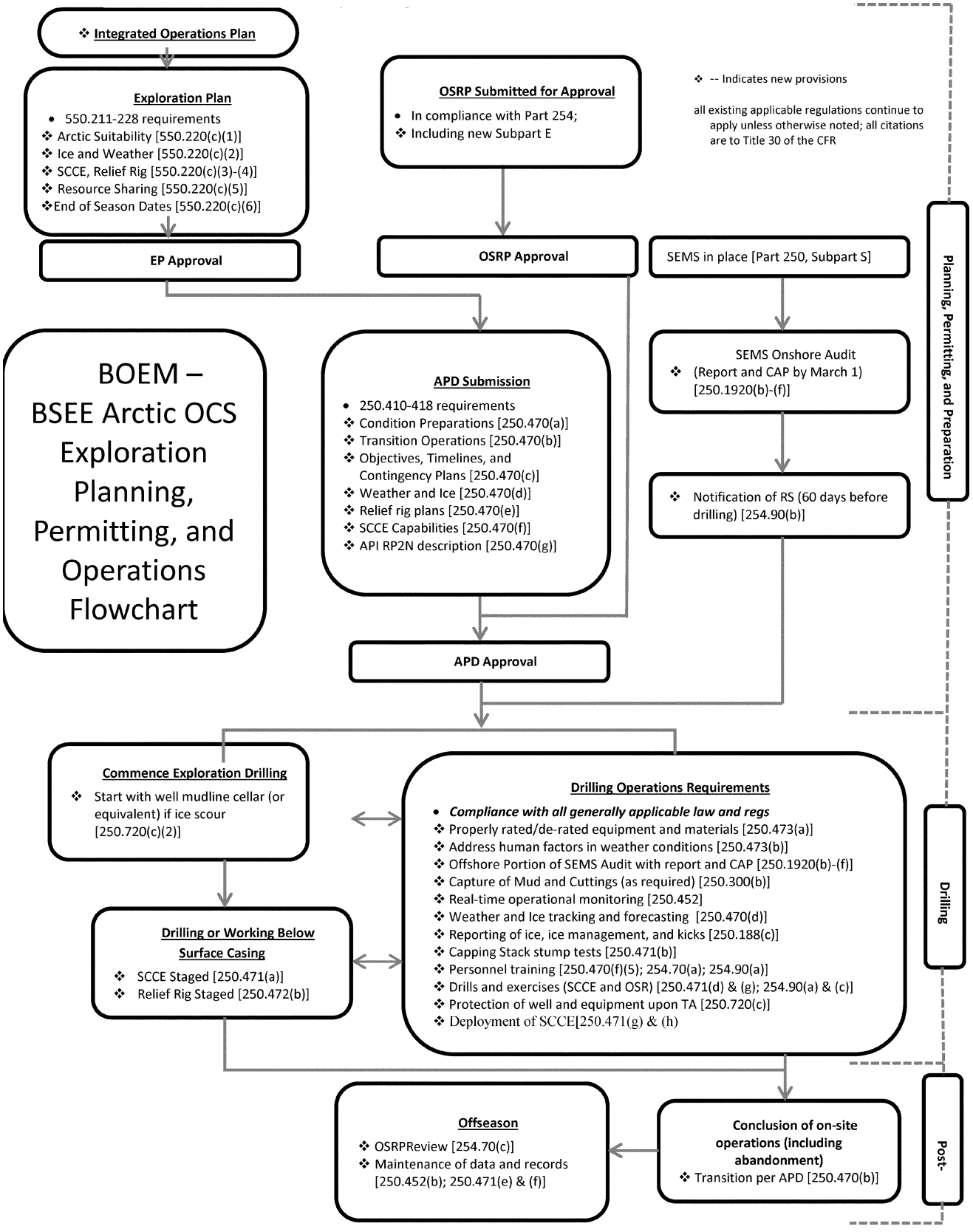
BOEM and BSEE considered comments on the relief rig requirements of the proposed rule. We have revised both the day rate cost for Arctic drilling rigs and revised the cost of the shoulder season as discussed above. The revised Arctic exploration scenario has assumed that all rigs are conducting exploratory drilling operations.

SEMS Auditing (§ 250.1920)

Two commenters question the auditing costs. One commenter is concerned that the cost estimated by BSEE for auditing services was underestimated by 50 percent. Another commenter thinks that the estimate of the incremental cost of the SEMS requirements was reasonable considering the scope of the requirement.

BSEE has recently updated its cost estimates for SEMS Audits and now estimates the average cost to audit a complex operation on the OCS at $250,000/audit cycle. BSEE believes that this incremental cost is more reasonable given the requirement that the audit provide an objective evaluation to test and contribute to continual improvements in the management system's ability to manage risk.

D. Arctic Exploratory Drilling Process Flowchart



E. Conclusion

The final rule establishes, through both performance-based and prescriptive requirements, what will be required of operators seeking to conduct exploratory drilling operations on the Arctic OCS. The requirements contained in the final rule reflect the unpredictable and challenging nature of exploratory drilling operations in the Arctic. The regulations require early and comprehensive planning of operations,

particularly with respect to safety systems and emergency response vessels and equipment. These regulations seek to ensure that operations are undertaken in a safe and environmentally responsible manner.

V. Procedural Matters

A. Regulatory Planning and Review (E.O. 12866 and E.O. 13563)

Changes to Federal regulations must undergo several types of economic analyses. First, E.O. 12866 and E.O. 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select a regulatory approach that maximizes net benefits (accounting for the potential economic, environmental, public health, and safety effects). E.O. 13563 emphasizes the importance of quantifying both costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. Under E.O. 12866, an agency must determine whether a regulatory action is significant and, thus, subject to the requirements of the E.O. and OMB review. Section 3(f) of E.O. 12866 defines a ''significant regulatory action'' as any rule that:

1. Has an annual effect on the economy of $100 million or more, or adversely affects in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities (also referred to as ''economically significant'');
2. Creates serious inconsistency or otherwise interferes with an action taken or planned by another agency;
3. Materially alters the budgetary impacts of entitlement grants, user fees, loan programs, or the rights and obligations of recipients thereof; or
4. Raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in E.O. 12866.

B. E.O. 12866

E.O. 12866 provides that OMB's OIRA will review all significant rules. Pursuant to the procedures established to implement section 6 of E.O. 12866, OMB has determined that this final rule is significant because it may have an effect on the economy of $100 million. The legal and policy issues identified by OMB are the requirements for SCCE, relief rig availability, and the shoulder season to reflect current conditions for Arctic OCS exploration plan and permit approval. The following discussion summarizes the economic analysis. The complete final RIA can be found in the regulatory docket for this final rule at *www.regulations.gov* (BSEE–2013–0011).

Before authorizing the exploration for Arctic OCS hydrocarbon resources, BOEM and BSEE must ensure that exploration can occur safely and with minimal environmental risk. This final rule provides a regulatory framework specifically designed for Arctic exploration and outlines the specific requirements for exploratory activities. Its purpose is to provide the requirements and standards to which all individual operations will be held.

The available Arctic OCS oil spill control and response capabilities have been strengthened at considerable cost over the last few years. The incremental compliance costs for new provisions required in this rulemaking are on top of measures already taken by industry. Two of the requirements of this regulation are considered baseline, that is, not new costs, as they reflect current industry practice under current regulations. At the same time, for informational purposes, we have accounted for this cost to industry of existing baseline requirements for exploratory operations in the Arctic that are being included in this rulemaking. The final RIA includes estimates of both new regulatory compliance costs and costs associated with the baseline.

While a catastrophic oil spill resulting from exploratory drilling on the Arctic OCS is highly unlikely due to the nature of the geology, the shallow water depth, and the relative simplicity of well construction for wells likely to be drilled in the Arctic OCS, because the potential adverse effects of a catastrophic oil spill would be severe, steps must be taken to reduce the risk of a spill risk and its duration should one occur. The American public greatly values the Arctic. It is viewed as a pristine, unspoiled environment. With this in mind, a catastrophic oil spill would have severe impacts (at least on a meaningful human time scale). BOEM and BSEE have determined that the benefits of this rule exceed the costs when qualitative factors are considered and reflect society's strong risk averse preference in the Arctic.

Economic Analysis

1.1 Compliance Costs

The provisions of the final rule are estimated to result in compliance costs of $2.0 billion under 3-percent discounting and $1.7 billion under 7-percent discounting over 10 years. The baseline provisions are estimated to cost $1.8 billion under 3-percent discounting and $1.5 billion under 7-percent discounting over 10 years.

Table 1 shows the final rule's provisions and primary benefit. We have included the estimated costs for reference. As the table emphasizes, the key provisions of this rule are specifically intended to minimize the risks of catastrophic oil spills and minimize the damage of a spill, should one occur.

TABLE 1—REGULATORY PROVISIONS, COSTS AND BENEFITS

Provision	Rule cost (discounted at 3% over 11 years, $ millions)	Baseline cost (discounted at 3% over 11 years, $ millions)	Primary benefit
(a) Additional Incident Reporting Requirements	$0.56	.....	Improves information to Federal agencies.
(b) Additional Pollution Prevention Requirements	141.09	.....	Minimizes natural resource impacts.
(c) Additional Requirements for Securing Wells *	.....	$1,811.912	Reduces risk of a spill.
(d) Real-time Monitoring Requirements **	.....	14.101	Reduces risk of a spill.
(e) Additional Information Requirements for APDs	0.23	.....	Improves information to Federal agencies.
(f) Incorporation of API RP 2N	0.08	.....	Reduces risk of a spill.
(g) Additional SCCE Requirements	681.92	.....	Improves control and containment of a spill.
(h) Relief Rig Requirements †	1,206.55	.....	Improves control of a spill.
(i) Additional Auditing Requirements	5.58	.....	Improves information to Federal agencies.
(j) Real-time Location Tracking Requirements	0.96	.....	Improves information to Federal agencies.
(k) IOP Requirements	7.67	.....	Improves coordination among Federal agencies.
(l) Planning Information Requirements to Accompany EPs.	2.57	.....	Improves information to Federal agencies.

TABLE 1—REGULATORY PROVISIONS, COSTS AND BENEFITS—Continued

Provision	Rule cost (discounted at 3% over 11 years, $ millions)	Baseline cost (discounted at 3% over 11 years, $ millions)	Primary benefit
(m) Industry Familiarization with the New Rule	0.37	.....	General.
Total	2,047.60	1,826.012	

* The drilling of mudline cellars has been a longstanding practice in the Chukchi and Beaufort Seas extending back to the 1980's; thus this provision is assigned to the regulatory baseline.

** The cost for this provision is assigned to the regulatory baseline. The BSEE BOP/Well Control rule at § 250.724 requires real-time monitoring for all operations with a subsea BOP or surface BOP on a floating facility.

† Provision (h) includes the baseline compliance cost attributable to the amount of time that an operator will ''lose'' from the open water season as a result of the relief rig/shoulder season requirement. A 116 day Arctic drilling season is estimated to be shortened by 34 days (29%).

1.2 Benefits

BOEM and BSEE have concluded that these exploratory drilling regulations will provide regulatory clarity and certainty, resulting in a more comprehensive Arctic OCS oil and gas regulatory framework. The provisions in this rule codify existing requirements in the Arctic designed to reduce the probability of a catastrophic spill, reduce the impacts of a spill should one occur, improve the coordination of operations among Federal agencies, and minimize natural resource and ecosystem impacts of offshore operations in the Arctic.

Due to both the uncertainty and difficulty of measuring benefits, we do not offer an aggregate quantitative assessment of all of the final rule's provisions. Instead, we present a combination of quantitative and qualitative discussions based on the benefits of the different provisions of this rule. In general, the individual provisions of this rule serve four main beneficial purposes: (1) Improving information to and coordination among Federal agencies regarding Arctic operations, (2) minimizing natural resource impacts, (3) reducing the risk of oil spills, including a catastrophic oil spill, and (4) improving containment and reducing severity of a catastrophic oil spill. Each of these benefits is discussed in more detail in the final RIA. In addition to these four main benefits, in aggregate the rule provides regulatory certainty to industry and the assurance to stakeholders and partners that DOI is committed to safe Arctic operations.

1.2.1 Benefit: Improving Information to, and Coordination Among Federal Agencies

The final rule includes new provisions that require additional information sharing and availability. Because the nature of this benefit is difficult to quantify, it is considered qualitatively. The costs of the applicable provisions total $17.6 million and comprise 0.9 percent of the compliance costs assigned to the rule. They are designed to achieve better coordination among BSEE, BOEM, and other Federal agencies. For example, § 550.204 requires operators to provide information which will facilitate interagency coordination between DOI and other relevant Federal agencies, as recommended in the DOI *Report to the Secretary of the Interior, Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program*.[47] The benefits of this information sharing allow different Federal agencies to manage potential conflicts and ensure compliance with environmental and regulatory standards. The necessity of coordination and information sharing between Federal agencies is documented in E.O. 13580, which created the Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska.[48] This E.O. recognizes the importance of interagency coordination for ''safe, responsible, and efficient development of oil and natural gas resources in Alaska . . . while protecting human health and the environment as well as indigenous populations.'' This rule provides assurance to other Federal agencies that BOEM and BSEE are protecting the region and are fostering communication and collaboration with government partners.

1.2.2 Benefit: Minimizing Natural Resource and Subsistence Impacts

The additional pollution prevention requirements in paragraphs (b)(1) and (2) of § 250.300 constitute 6.9 percent of the rule's estimated compliance cost. The revised pollution prevention requirements that are responsible for these incremental compliance costs clarify the Regional Supervisor's discretionary authority to ensure that operators capture all water-based muds and associated cuttings from Arctic OCS exploratory drilling operations following completion of the conductor casing to prevent discharge of these water based muds and associated cuttings into the marine environment. The Regional Supervisor would be more likely to exercise authority requiring the capture of water-based muds and cuttings in the Beaufort Sea, as that is the area where whales migrate through subsistence harvest areas. Given the difficulty of calculating how the discharge of muds and cuttings could affect marine mammals, their habitat, and subsistence activities, we have not quantified the benefits of these provisions. However, we recognize the importance of subsistence harvests in the region and conclude these provisions are necessary to preserve a food source and cultural tradition.

1.2.3 Benefit: Reducing the Risk of a Catastrophic Oil Spill

Both the provision for RTM and the additional requirements for securing wells help reduce the risk of a catastrophic oil spill from Arctic OCS exploration activities. These baseline provisions are designed to reduce the risk of such an oil spill occurring.

A catastrophic oil spill is characterized as a ''low-probability, high-consequence'' event because it is infrequent but has large consequences when it does occur. Previous frequency/probability studies of oil spills resulting from loss of well control have estimated catastrophic oil spill risk, but also have emphasized the extreme difficulty in estimating the probability that an event will actually occur, in part because the number of such large accidents offshore is small. Even more difficult is determining the reduction in the

[47] *http://www.doi.gov/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf.*

[48] *https://www.whitehouse.gov/the-press-office/2011/07/12/executive-order-13580-interagency-working-group-coordination-domestic-en.*

probability of occurrence that a new regulation would actually achieve. Given the nature of the new requirement being imposed on industry as a result of this provision (*i.e.,* additional documentation that the recommended practice was followed), we have not quantified the effect of this provision on the reduction in risk or the estimated avoided spill costs associated with the provision. The benefits of the final rule's baseline provisions are discussed in the final RIA.

1.2.4 Benefit: Reducing the Duration of Catastrophic Oil Spills

Provisions of this final rule are designed to ensure that equipment and personnel are readily available to respond to a loss of well control event. As shown in Table 1 in the RIA, the most costly provisions are designed to reduce the duration of a loss of well control event should one occur. To compare the benefit of reducing the duration or severity of a catastrophic oil spill with the costs incurred, the final RIA conducts analyses on the specific provisions of the rule designed to reduce spill duration or severity. Section 250.471 of the final rule requires additional SCCE testing and documentation, which can reduce the impact of a catastrophic oil spill should one occur. Section 250.472 requires Arctic OCS operators to have access to a separate relief rig that would be available if a loss of well control was to occur and drilling a relief well became necessary. The rule requires a drilling rig be located such that it could arrive on location, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected ice encroachment at the drill site, but no later than 45 days after a loss of well control. The SCCE and relief rig requirements make up 92 percent of the rule's compliance cost.

The SCCE testing requirements can help reduce the duration of catastrophic oil spills in two ways. First, through regular tests of the SCCE, crew members gain practice and experience in deploying the equipment which could ultimately lead to faster and more efficient deployment should an oil spill occur. Second, through these regular tests crew members can identify faulty equipment. This allows problems to be corrected before the equipment is actually needed.

Given the difficulties associated with quantifying the exact influence this provision could have on reducing the severity of an oil spill, we conducted an analysis of the SCCE testing requirements. The final RIA includes calculations for the smallest reduction in oil spill duration, due to the SCCE testing requirements, necessary for this provision of the rule to be cost-beneficial. Also included in the final RIA is a risk analysis that considers the historical frequency of catastrophic OCS oil spills.

1.2.5 Benefit: Regulatory Certainty to Industry

The regulatory baseline includes recent Arctic OCS exploration best practices and regulatory requirements that are being clarified and codified in this rule. Therefore, a benefit of this final rule is to provide the regulatory certainty of what is required for operators to safely explore for hydrocarbons on the Arctic OCS.

The oil and gas industry requires regulatory stability to undertake timely and efficient exploration. With this rule, the oil and gas industry can more effectively plan and conduct exploratory drilling on the Arctic OCS with lower risk and fewer delays than under the existing rules and clarifying NTLs. According to BOEM's 2016 Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, there are approximately 23.6 billion barrels of technically recoverable oil and about 104.4 trillion cubic feet of technically recoverable natural gas in the Beaufort Sea and Chukchi Sea Planning Areas combined. The NPC Arctic Potential Study listed as one of its key findings that the ''economic viability of U.S. Arctic development is challenged by operating conditions and the need for updated regulations that reflect arctic conditions'' (p. 10). This rule provides those Arctic-specific regulatory requirements.

1.2.6 Benefit: Assurance to Stakeholders and Partners

In addition to providing regulatory certainty to industry, another benefit of this rule is to provide assurance to stakeholders, partners, Tribes, citizens, and other countries that the U.S. will explore the Arctic safely and with appropriate environmental stewardship. This rule builds on one of the themes from the NPC Arctic Potential Study that steps must be taken to ''secure public confidence'' that activities can be conducted safely. This rule helps achieve the National Arctic Strategy goals of protecting the unique and sensitive Arctic ecosystems and the subsistence needs, culture, and traditions of the Alaska Native communities.

The U.S. Arctic Policy recognizes the interconnectedness of Arctic nations and commits to coordinating with other Arctic nations to ensure operationally safe and environmentally sustainable development. The U.S. is a Party to the Agreement on Cooperation on Marine Oil Pollution Preparedness and Response in the Arctic and must comply with the Agreement, including the provisions in Article 4: Systems for Oil Pollution Preparedness and Response. These regulations help provide assurances to the international community that our operators in the Arctic will follow the appropriate preparedness procedures and do everything possible to prevent an oil spill, or minimize the effects should one occur. Further, the NPC Arctic Potential Study cites the importance of the U.S. national Arctic strategy in promoting Arctic activities because of their interaction with national security, foreign policy, and energy policy. The goal of the Arctic strategy is to ''seek an Arctic region that is stable and free of conflict, where nations act responsibly in a spirit of trust and cooperation, and where economic and energy resources are developed in a sustainable manner that respects the fragile environment and the interests and cultures of indigenous peoples.'' [49]

C. E.O. 13563

E.O. 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. In addition, E.O. 13563 directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. It also emphasizes that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We developed this final rule in a manner consistent with these requirements. BOEM and BSEE worked closely with engineers and technical staff to ensure this rulemaking follows sound engineering principles through research, standards development, and interaction with industry.

E.O. 13563 requires an analysis of employment impacts. BOEM and BSEE considered whether the regulation might adversely affect Alaska employment by reducing the potential for jobs associated with the offshore oil

[49] NPC Arctic Potential Study, Executive Summary, p. 9 (March 2015).

and gas industry. The Arctic region of Alaska has not relied previously on Federal offshore oil production for economic development, but any eventual production would be a positive contribution to the State's and the Nation's economic development. Although BOEM and BSEE, when considering the cumulative impacts of Arctic specific provisions in this rule, acknowledge reduced employment might occur, the safety and environmental protections are necessary to protect our fragile Arctic natural resources.

Conversely, the final rule brings potential benefits to the local economy and cultural traditions from reduced risk of spills. A catastrophic spill would have negative economic impacts far beyond the offshore oil and gas industry. A catastrophic spill could disrupt subsistence whaling on which Native Alaskans rely for food and for their cultural preservation. Thus, assessing the net cost or benefit of the rule to the local economy is not practical, given the number of factors involved and the level of uncertainty that surrounds each of them.

E.O. 13563 encourages agencies to consider the cumulative cost of regulations. Consistent with E.O. 13563 and OMB guidance in the March 20, 2012, memorandum from the Administrator for the OIRA, the final RIA has made an effort to ''take account of the cumulative effects of new and existing rules.'' Thus, the RIA appendix accounts for the significant regulatory baseline costs codified in this rulemaking.

D. Regulatory Flexibility Act

For the reasons explained in this section, BOEM and BSEE have concluded this rule will not have a significant economic impact on a substantial number of small entities and, therefore, a final regulatory flexibility analysis is not required.

BOEM and BSEE prepared an Initial Regulatory Flexibility Analysis (IRFA) for the proposed rule to assess the impact of the proposed rule on small entities, as defined by the applicable Small Business Administration size standards. The IRFA was prepared using conservative assumptions and sought public comments on potential small entity impacts. No comments on the potential impact to small entities were received during the proposed rule comment period. Based on the profile of current Arctic lessees, no small companies hold leases on the Arctic OCS. Previously only one small company holding only one lease held acreage in the Arctic. This company relinquished its lease in March 2016. Considering the past and current Arctic lease holding profiles and the challenges of operating in the Arctic, we certify that this final rule will not have a significant economic impact on a substantial number of small entities.

The final rule affects operators and Federal oil and gas lessees that could conduct exploratory drilling on the Arctic OCS. The Regulatory Flexibility Act, 5 U.S.C. 601–612, defines small entities as small businesses, small nonprofits, and small governmental jurisdictions. We have identified no small nonprofits or small governmental jurisdictions that the rule would impact. Businesses subject to this rule fall under North American Industry Classification System (NAICS) codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells). For these classifications, a small business is defined as one with fewer than 1,250 employees (NAICS code 211111) and fewer than 1,000 employees (NAICS code 213111), respectively. A small entity is one that is ''independently owned and operated and which is not dominant in its field of operation.''

Consistent with the exploratory scenario for the final RIA analysis, BOEM and BSEE anticipate three businesses to conduct exploratory drilling on the Arctic OCS over the 10 years of analysis. Although any business holding a lease could conduct exploratory drilling on the Arctic OCS if it can meet the relevant BOEM and BSEE regulatory requirements, a viable Arctic exploratory drilling program requires large geologic prospects and sufficient acreage to identify multiple drilling locations to support the prospect of economically viable development. Even absent this rulemaking, a single season of Arctic OCS exploratory drilling is estimated to cost approximately $1.5 billion and may only result in one or two exploratory wells being drilled.

According to BOEM's May 2016 list of Arctic OCS leaseholders, six businesses currently hold lease interests on the Arctic OCS. This rule directly affects all six Arctic lessees. Based on the small entity criterion, none of the six businesses is considered a small entity. From inception, to execution, to completion, every phase of Arctic OCS operations comes with inherent challenges and operational risks. The inherent challenges, including prospect and operational risks, and the attendant costs, make it exceedingly unlikely that any small entity will choose to conduct exploratory drilling operations on the Arctic OCS over the next decade.

Consistent with the existing and inherent costs and challenges associated with Arctic OCS exploratory drilling, the absence of interested and capitalized small entity lessees, and the 10-year scenario in which only three operators engage in Arctic OCS exploratory drilling, BOEM and BSEE certify that this rule will not have a significant economic impact on a substantial number of small entities.

E. Unfunded Mandates Reform Act of 1995 (UMRA)

This final rule will not impose an unfunded Federal mandate on State, local, or Tribal governments. This rule will require expenditures exceeding $100 million in a single year by offshore oil and gas exploration companies operating on the Arctic OCS. DOI has prepared written statements satisfying the applicable requirements of the UMRA, 2 U.S.C. 1501 *et seq.* Those requirements are addressed in the RIA and in the final rule itself.

Among other things, the final rule and the final RIA:

1. Identify the provisions of Federal law (OCSLA, CWA, and OPA) under which this rule is being finalized;

2. Include a quantitative assessment of the anticipated costs to the private sector (*i.e.,* expenditures on labor and equipment) of the final rule; and

3. Include qualitative and quantitative assessments of the anticipated benefits of the final rule.

Since all of the anticipated expenditures by the private sector analyzed in the RIA would be borne by the OCS oil and gas exploration industry in the Arctic region, the RIA analyses satisfy the UMRA requirement to estimate any disproportionate budgetary effects of the final rule on a particular segment of the private sector (*i.e.,* the offshore oil and gas industry).

As discussed in the Regulatory Planning and Review section of this final rule, and explained in the RIA, BOEM and BSEE considered two major regulatory alternatives for dealing with the safety and environmental concerns raised by exploration activities on the Arctic OCS. BOEM and BSEE have decided to move forward with this final rule, in lieu of the other alternative of taking no regulatory action, because the other alternative would not as efficiently or effectively address the safety, environmental or sociocultural concerns raised by various stakeholders and partners on the Arctic OCS or achieve the objectives of this final rule.

BOEM and BSEE have determined that the final rule would not impose any unfunded mandates or any other requirements on State, local or Tribal

governments; thus, the final rule would not have disproportionate budgetary effects on such governments. Assuming, however, that the final rule might result in budgetary effects on the Arctic region, BOEM and BSEE have determined that it is not practical to accurately estimate such effects. Since the final rule would not impose any requirements on any entities, other than upstream oil and gas companies and their contractors engaged in Arctic OCS exploration activities, any budgetary effects in that area would be at least indirect, secondary results of actions or decisions taken by regulated (or unregulated) entities, based on a variety of circumstances (such as the price of oil, each entity's overall financial health, and the prospects of success of any exploratory drilling). Because each of those factors is variable and unpredictable, it is not practical to estimate how those factors might affect an entity's future decisions, or what indirect impacts, if any, such decisions could have on future regional budgets.

Similarly, BOEM and BSEE have determined that it is not reasonably feasible to accurately estimate the potential effects, if any, of the final rule on the National economy (*e.g.,* productivity, economic growth, employment, international competitiveness). The final rule would only affect exploratory drilling activities on the Arctic OCS, and any potential impact on the national economy would depend on the economics of any hydrocarbon discoveries and individual business decisions made by regulated entities (*e.g.,* whether or not to hire new employees). Moreover, any such decisions would likely be either local or regional in effect and unlikely to have any significant national economic impacts.

F. Takings Implication Assessment

Under the criteria in E.O. 12630, this final rule will not have significant takings implications. The final rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

G. Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this final rule will not have federalism implications. This final rule will not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this final rule will not affect that role. A Federalism Assessment is not required.

H. Civil Justice Reform (E.O. 12988)

This final rule complies with the requirements of E.O. 12988. Specifically, this rule:

1. Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

2. Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

I. Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, Consultation and Coordination with Indian Tribal Governments (dated November 6, 2000), DOI's Policy on Consultation with Indian Tribes (Secretarial Order 3317, Amendment 2, dated December 31, 2013), the Alaska Native Corporation Consultation Policy (dated August 12, 2012), and Departmental Manual Part 512 Chapters 4 and 5 (dated December 2, 2014), we evaluated and determined that the subject matter of this rulemaking will have implications for federally recognized Tribes and ANCSA Corporations. As described earlier, future Arctic OCS exploratory drilling activities conducted pursuant to this final rule could affect Alaska Natives, particularly their ability to engage in subsistence and cultural activities.

BOEM and BSEE are committed to regular and meaningful consultation and collaboration with Tribes on policy decisions that have Tribal implications including, as an initial step, through complete and consistent implementation of E.O. 13175, together with related orders, directives, and guidance. Therefore, BOEM and BSEE, in coordination with the Office of the Secretary of the Interior's Senior Alaska Representative, engaged in listening sessions, Government-to-Government Tribal consultations, and Government-to-ANCSA Corporations consultations to discuss the subject matter of the final rule and solicit input in the development of the final rule at several stages of the rule development process, from the earliest phases through the final rule development.

In the early stages of developing the NPRM, Government-to-Government consultation was held in Barrow between BOEM, BSEE, and the Inupiat Community of the Arctic Slope (ICAS), to both provide background to, and obtain information from, ICAS tribal leaders and council members. The following day, June 7, 2013, BOEM and BSEE met with leaders and council members of the Native Village of Barrow Inupiat Traditional Government in a separate Government-to-Government consultation. All Tribal input provided during the meetings was subsequently provided to DOI in writing and has been included in the decision record for this final rule.

BOEM and BSEE also held public listening sessions in South-central Alaska (Anchorage) and on the North Slope (Barrow) on June 6 and 7, 2013. The BOEM Alaska Region notified federally recognized Alaska Native Tribes and ANCSA Corporations of the June 6 and 7, 2013, public listening sessions and Government-to-Government consultations through phone calls, emails, newspaper announcements, and BOEM's Web site.

A series of follow-on meetings and listening sessions were held June 17–20, 2013, in Anchorage resulting, in part, in Government-to-Government consultation between BOEM, BSEE, and the Native Village of Nuiqsut and Government-to-ANCSA Corporation consultations between BOEM, BSEE, and the NANA Regional Corporation and the Cully Corporation (Point Lay ANCSA Corporation).

DOI continued consultation with affected federally recognized tribes and ANCSA Corporations following publication of the NPRM. On March 12, 2015, BOEM and BSEE held a public meeting in Barrow and met individually with leaders and council members of the Native Village of Barrow Inupiat Traditional Government, the AEWC and ICAS. The Bureaus also met with federally recognized Tribal leaders for six Government-to-Government consultations on the proposed regulations between April 20 and 24, 2015. The consultations were held in the following Alaskan locations: Kotzebue, Point Hope, Barrow, and Wainwright. During that week, consultations were held with the Native Village of Kotzebue, Native Village of Point Hope, ICAS, Native Village of Barrow, and Village of Wainwright. We also met with the president of the AEWC. On July 9, 2015, an additional Government-to-Government consultation was conducted with the Native Village of Nuiqsut by telephone conference.

Alaska Native Tribes' and ANCSA Corporations' comments on the proposed regulations, both written and oral, and the Bureaus' responses are summarized in this preamble (see Section IV *Section-By-Section Discussion of Changes and Comments*). ANCSA corporations primarily supported more performance-based regulations and recommended the

proposed rule be withdrawn. Conversely, Alaska Native Tribes primarily supported the proposed regulations and recommended strengthening the provisions. Both written and oral comments received during Government-to-Government and Government-to-ANCSA Corporation consultations emphasized the importance of safe drilling operations. Discussions were primarily focused on impacts to, and protection of, subsistence hunting and fishing areas and species, including consideration of mammal and fish migratory patterns, hunting and fishing seasons, and impacts of pollutants and equipment movements. Concerns also included the relative lack of infrastructure, such as roads, housing, and equipment in coastal communities near proposed Arctic OCS oil and gas exploration areas, and inclusion of local Alaska Natives in monitoring and other activities. Commenters also requested that we incorporate traditional knowledge of the Arctic OCS into our decision-making for regulations. As discussed in Section IV, BOEM and BSEE have considered Alaska Native Tribes' and ANCSA Corporations' comments and incorporated them in the final rule as appropriate. For example, Alaska Native Tribes expressed concern over drilling mud and cuttings from exploratory activities adversely affecting marine species and impacting subsistence hunting. As a result, BSEE is requiring the capture of all petroleum-based mud and associated cuttings from Arctic OCS exploratory drilling operations. Capturing of water based mud and cuttings could also be required based on proximity to subsistence hunting, fishing locations, and potential effects on marine mammals and birds.

Only one commenter, the Cully Corporation, submitted a written comment asserting the Bureaus did not comply with the requirement to consult on this rulemaking.

Both BOEM and BSEE have sought and maintained an active relationship with the Cully Corporation. With respect to Cully Corporation's statement that neither Bureau consulted with them, it is important to note that both Bureaus did make an effort to reach out to Cully Corporation regarding this particular matter. We met with the Cully Corporation several times prior to the publication of the NPRM, including a Government-to-ANCSA Corporation consultation in June 2013. Another Government-to-ANCSA Corporation consultation was scheduled with Cully Corporation on April 21, 2015. We welcome the opportunity to discuss the Cully Corporation's concerns regarding implementation of this final rule, and thank them for the thoughtful and comprehensive written comments submitted on the proposed regulations.

J. E.O. 12898—Environmental Justice

E.O. 12898 requires Federal agencies to make achieving environmental justice part of their mission by identifying and addressing disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and low-income populations. DOI has determined that this final rule does not have a disproportionately high or adverse human health or environmental effect on native, minority, or low-income communities because its provisions are designed to increase environmental protection and minimize any impact of exploration drilling on subsistence activities and Alaska Native community resources and infrastructure.

K. Paperwork Reduction Act (PRA)

This rule contains information collection (IC) requirements for both BOEM and BSEE regulations. Therefore, an IC request for each Bureau was submitted to OMB for review and approval under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et. seq.*); see each individual bureau's section for the OMB Control number, expiration date, and relevant information. The Paperwork Reduction Act (PRA) provides that an agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public may submit comments at any time on the IC burden in this rule to either DOI/BOEM: ATTN: Office of Policy, Regulation and Analysis; OPRAVAM–BOEM–DIR or DOI/BSEE; ATTN: Regulations and Standards Branch; VAE–ORP; 45600 Woodland Road, Sterling, VA 20166.

As part of our continuing effort to reduce paperwork and respondent burdens, BOEM and BSEE invited the public to comment on any aspect of the reporting and recordkeeping burdens. We received 1,311 comments on this rulemaking. Three comments pertained to the information collection for BOEM and BSEE.

Commenters generally criticized the IOP provision as being duplicative or redundant of existing requirements. BOEM disagrees. The IOP rules are neither redundant nor duplicative of existing requirements. The IOP is meant to be an overview of all phases of the operator's proposed operations in order to allow the Federal agencies an earlier review in the planning process than currently exists. Moreover, the operator's IOP will contain planning information with less specificity than that furnished with the EP; as well as, the IOP will not require approval where the EP does require approval.

One of the commenters estimates that it will require 3,500 hours of industry staff time. We agree with the commenter that 90 hours for an IOP is low. However, we disagree with the commenter's recommendation to revise to 3,500 hours. BOEM anticipates that much of the conceptual planning information would already have been created by an operator planning to conduct exploration in the Arctic, and an IOP can be furnished through the operator's existing internal planning processes necessary for the preparation of Arctic operations. BOEM uses a conservative estimate derived from comments submitted by industry and direct experience reviewing a company's previously submitted IOP. During the IOP review period, BOEM can provide input to the operator, as well as request information from the operator regarding potential issues presented by the proposed activities concerning future plan approvals and permitting requirements. The estimated time it would take for the operator to provide any requested information to BOEM during the IOP review period is included in its burden hours estimate.

Therefore, based on comments received, changes to BOEM's hour burdens are as follows:

§ 550.204 submit all Arctic specific information required with IOP (+2,700).

§ 550.220 submit all Arctic specific information required with EP (+960).

Another comment received discussed duplicative information being submitted with the EP and the APD. BSEE and BOEM disagree with the duplication of information because the EP is intended to provide the operator the opportunity to present its overall plan for operations, and the APD is the technical document that provides the operator the opportunity to present details regarding how the plan will be implemented.

The commenter also discussed the burden hours being low, for example, the submission of detailed descriptions of environmental, meteorologic, and oceanic conditions expected at well site(s); etc. BSEE agrees and has increased two of the hour burdens associated with certain requirements. The changes are as follows:

§ 250.470(a); 417; 418—NEW—Submit detailed descriptions of environmental, meteorological, and oceanic conditions (+10 burden hours).

§ 250.470(d); 418—NEW—Submit detailed description concerning weather

and ice forecasting for all phases; etc., (+6 hours).

One commenter suggested the regulations should implement performance based requirements for well containment, which recognizes acceptable alternatives to mud line cellars. BSEE agrees with the importance of allowing for the use of technology that is best suited to an operator's plan and has changed the burden as follows:

§ 250.720(c)(2)—NEW—Request approval to use an equivalent means rather than a well mudline cellar in areas of ice scour (+28 hours).

Another change that occurred to the BSEE information collection between the proposed and final rulemaking is the IC renewal for 30 CFR part 250, subpart S was initiated. When requests went out to industry for updated burdens, it was determined that the cost to conduct an audit has increased from $129,000 to $217,000. Based on a comment pertaining to the Regulatory Impact Analyses, it was decided that a SEMS audit in the Arctic will cost $250,000 (+$121,000).

BSEE Information Collection—30 CFR Parts 250 and 254

The title of the collection of information for this rule is 30 CFR parts 250 and 254, Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf. The OMB approved the collection under Control Number 1014–0027, expiration 06/30/2019, 779 hours, $250,000 non-hour cost burdens. The regulations establish requirements for safe, responsible, and environmentally protective Arctic OCS oil and gas exploration, and the information is used in our efforts to protect life and the environment, conserve natural resources, and prevent waste.

Potential respondents comprise Federal OCS oil, gas, and sulfur operators and lessees on the Arctic OCS. The frequency of response varies depending upon the requirement. Responses to this collection of information are mandatory; they are submitted on occasion, annually, or as a result of situations encountered, depending upon the requirement. The IC does not include questions of a sensitive nature. BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and DOI's implementing regulations (43 CFR part 2), 30 CFR part 252, and 30 CFR 250.197, which address disclosure of data and information to be made available to the public.

As stated previously, this rulemaking also pertains to several regulations. Once this rule becomes effective, the paperwork and non-hour cost burdens will be removed from this collection of information and consolidated with the IC burdens under OMB Control Numbers 30 CFR part 250, subpart A, 1014–0022, expiration 8/3/2017 (84,391 hours, $1,371,458 non-hour cost burdens); subpart D, 1014–0018, expiration 10/31/2017 (102,512 hours); subpart S, 1014–0017, expiration 11/30/2018 (2,238,164 hours, $5,220,000 non-hour cost burdens); and 30 CFR part 254, 1014–0007, expiration 11/30/2018 (74,461 hours) respectively; current collections can be viewed at *www.reginfo.gov/public/.*

BURDEN BREAKDOWN

Citation 30 CFR parts 250 and 254	Reporting and recordkeeping requirements	Hour burden	Average number of annual responses	Annual burden hours
30 CFR Part 250, Subpart A				
141	Request approval to use new or alternative procedures, along with supporting documentation if applicable, including BAST not specifically covered elsewhere in regulatory requirements.	Burden covered under 30 CFR part 250, subpart A, 1014–0022.		0
188(c); 190	NEW—Provide BSEE immediate oral report of sea ice movement/conditions; start and termination of ice management activities; kicks or unexpected operational issues.	Oral 1.5	2 notifications	3
188(c); 190	NEW—Submit a written report within 24 hours after completing ice management activities.	Written 4	2 reports	8
Subtotal			4 responses	11
30 CFR Part 250, Subpart C				
300(b)(1)(2)	Obtain approval to add petroleum-based substance to drilling mud system or approval for method of disposal of drill cuttings, sand, & other well solids, including those containing NORM.	Burden covered under APDs or APMs 1014–0025 or 1014–0026.		0
30 CFR Part 250, Subpart D				
418	Additional information that is to be submitted with an APD is covered under the specific requirement listed in this burden table under 30 CFR 250.470			0
452(a), (b)	NEW—Immediately transmit real-time data gathering and monitoring to record, store, and transmit data relating to the BOP control system, fluid handling, downhole conditions; prior to well operations, notify BSEE of monitoring location and make data available to BSEE upon request.	12	1 transmittal	12
452(b)	NEW—Store and monitor all information relating to § 250.452(a); make data available to BSEE upon request.	1	2 wells × 138 drilling days = 276.	276

BURDEN BREAKDOWN—Continued

Citation 30 CFR parts 250 and 254	Reporting and recordkeeping requirements	Hour burden	Average number of annual responses	Annual burden hours
452(b)	Store and retain all monitoring records per requirements of §§ 250.466 and 467.	Burden covered under 30 CFR part 250, subpart D, 1014–0018.		0
470(a); 713; 418	NEW—Submit detailed descriptions of environmental, meteorologic, and oceanic conditions expected at well site(s); how drilling unit, equipment, and materials will be prepared for service; how the drilling unit will be in compliance with § 250.417.	20	1 submittal	20
470(b); 418	NEW—Submit detailed description of transitioning rig from being underway to drilling and vice versa.	4	2 each well–underway to drilling; drilling to underway = 4.	16
470(b); 418	NEW—Submit detailed description of any anticipated repair and maintenance plans for the drilling unit and equipment.	2	2 submittals	4
470(c); 418	NEW—Submit well specific drilling objectives, timelines, and updated contingency plans etc., for temporary abandonment.	4	2 submittals	8
470(d); 418	NEW—Submit detailed description concerning weather and ice forecasting for all phases; including how to ensure continuous awareness of weather/ice hazards at/between each well site; plans for managing ice hazards and responding to weather events; verification of capabilities.	12	1 submittal	12
470(e); 418; 472	NEW—Submit a detailed description of compliance with relief rig plans.	140	1 description	140
470(f); 471(c); 418	NEW—SCCE capabilities; submit equipment statement showing capable of controlling WCD; detailed description of your or your contractor's SCCE capabilities including operating assumptions and limitations; inventory of local and regional supplies and services, along with supplier relevant information; proof of contract or agreements for providing SCCE or supplies, services; detailed description of procedures for inspecting, testing, and maintaining SCCE; and detailed description of your plan ensuring all members of the team operating SCCE have received training to deploy and operate, include dates of prior and planned training.	60	2 submittals	120
470(g); 418	NEW—Submit a detailed description of utilizing best practices of API RP 2N during operations..	20	1 submittal	20
471(c); 470(f); 465(a)	NEW—Submit with your APM, a reevaluation of your SCCE capabilities if well design changes; include any new WCD rate and demonstrate that your SCCE capabilities will comply with § 250.470(f).	10	2 submittals	20
471(e)	NEW—Maintain all SCCE testing, inspection, and maintenance records for at least 10 years; make available to BSEE upon request.	20	2 records	40
471(f)	NEW—Maintain all records pertaining to use of SCCE during testing, training, and deployment activities for at least 3 years; make available to BSEE upon request.	20	2 records	40
472(c)	Request approval for alternative compliance for relief rig requirements.	Burden covered under 30 CFR part 250, subpart A, 1014–0022		0
720(c)(2)	NEW—Request approval to use an equivalent means other than a well mudline cellar in areas of ice scour.	14		2 request
Subtotal			299 responses	756
30 CFR Part 250, Subpart S				
1920(b), (c), (f)	ASP audit for High Activity Operator. NOTE: An audit once every 3 years in POCSR and GOMR; an audit in the Arctic in every year in which drilling is conducted (and the audit would cost more in the Arctic than in POCSR or GOMR).	1 operator × $250,000 audit for high activity = $250,000.		
1920(c)	Submit to BSEE after completed audit, an audit report of findings and conclusions, including deficiencies and required supporting information/documentation.	Burden covered under 30 CFR part 250, subpart S, 1014–0017.		0
1920(d)	Submit/resubmit a copy of your CAP that will address deficiencies identified in audit.			

BURDEN BREAKDOWN—Continued

Citation 30 CFR parts 250 and 254	Reporting and recordkeeping requirements	Hour burden	Average number of annual responses	Annual burden hours
Subtotal			1 response	0
			$250,000 Non Hour Cost Burdens	
30 CFR Part 254, Subpart E				
55; 70; 80; 90	Submit spill response plan for OCS facilities with all information required in regulations and related documents.	Burden covered under 30 CFR part 254, 1014–0007.		0
80(c)	NEW—Submit a description of system used to maintain real-time location tracking for all response resources.	6	2 descriptions	12
90(a)	Include in your training and exercise activities the requirements of this section.	Burden covered under 30 CFR part 254, 1014–0007.		0
90(b)	Notify BSEE 60 days prior to handling, storing, or transporting oil.			
Subtotal			2 responses	12
Total Hour Burden			306 responses	779
			$250,000 Non-Hour Cost Burdens	

BOEM Information Collection—30 CFR Part 550

This final rulemaking adds new requirements for submitting EPs and other information before conducting oil and gas exploration drilling activities on the Arctic OCS. The title of the collection for the rulemaking is 30 CFR part 550, subpart B, Arctic OCS Activities. The OMB approved the collection under Control Number 1010–0189, expiration 06/30/2019, 3,930 hours, and no non-hour cost burdens.

Respondents for this rulemaking are Federal oil, gas, or sulfur lessees and/or operators on the Arctic OCS.

Submissions are mandatory. BOEM collects the information to ensure that planned operations will be safe; will not adversely affect the marine, coastal, or human environments; will respond to the special conditions on the Arctic OCS; and will conserve the resources of the Arctic OCS. BOEM uses the information to ensure, through advanced planning, that operators are capable of safely operating in the unique environmental conditions of the Arctic and to make informed decisions on whether to approve EPs as submitted or whether modifications are necessary. BOEM also plans to share the preliminary information submitted in the IOP with other relevant agencies to provide them the opportunity to engage in constructive dialogue/feedback with operators, and each other, early in the process.

The burdens for the current planning requirements under 30 CFR part 550, subpart B, regulations are approved by OMB under Control Number 1010–0151 (432,512 hours, $3,939,435 non-hour costs; expiration 3/31/2018; the current collection can be viewed at *www.reginfo.gov/public/*). When these final regulations become effective, the new IC burdens will be consolidated into the existing collection for subpart B.

BURDEN BREAKDOWN

Citation 30 CFR part 550, subpart B	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
Arctic Integrated Operations Plan (IOP)				
New—204	For New Arctic OCS Exploration Activities: Submit IOP, including all required information.	2,880	1	2,880
Contents of Exploration Plans (EP)				
206	General requirements for plans.	Burdens already covered under plans in 1010–0151.		0
220	Submit Alaska-specific information..			
Expanded—220	For New Arctic OCS Exploration Activities: Submit required Arctic-specific information with EP, including confirmations.	350	1	350

BURDEN BREAKDOWN—Continued

Citation 30 CFR part 550, subpart B	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours
Expanded—220	For Existing Arctic OCS Exploration Activities: Revise and resubmit Arctic-specific information, as required.	700	1	700
Total Burden	.....	.....	3	3,930

L. National Environmental Policy Act of 1969 (NEPA)

BOEM and BSEE developed a final Environmental Assessment (EA) and have determined this final rule does not have a significant impact on the quality of the human environment under the NEPA. The final EA and Finding of No Significant Impact is available in conjunction with this final rule at *www.regulations.gov* (BSEE–2013–0011).

M. Data Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C section 515, 114 Stat. 2763, 2763A–153–154).

The Bureaus received two comments on the Data Quality Act. One comment asserted the NPRM, the Draft EA and the initial RIA violated the Information Quality Act (IQA) peer review requirements as well as associated IQA Guidelines.

We disagree. The IQA applies to information disseminated by Federal agencies and establishes basic quality performance goals for such information.[50] However, the IQA is not applicable to this rulemaking, including the associated Draft EA or initial RIA, because the Bureaus did not disseminate materials with information subject to the IQA. The rulemaking and associated analyses contain information the Bureaus relied on during the formulation of the final rule. The Bureaus made the proposed rulemaking publicly available and sought public input. However, we did not ''disseminate'' (*i.e.,* conduct an agency-sponsored distribution of information to the public) a study, analysis, or other [similar] information as part of this rulemaking that implicates the IQA.[51] Accordingly, the IQA does not apply to the actions associated with this rulemaking.

The second comment recommended the IC Requests in this final rule should be withdrawn by DOI or denied by OMB because the DOI burden estimates and the rest of the PRA analysis violate the IQA requirement for peer review as well as OMB and DOI IQA guidelines.

BOEM and BSEE disagree. The IC Requests are publicly available, but they are not disseminated to the public as that term is used in the IQA. In other words, the ICRs reflect information on which the Bureaus relied in reaching their decision, not an agency-sponsored distribution of information to the public. Therefore, the IQA, including the peer-review provisions, is not implicated by the content of the Bureaus' IC Request submissions to OMB. Also, the Bureaus' IC Requests have reasonably demonstrated that they have practical utility under the OMB definition, and the commenter provides no legitimate legal reason for recommending their withdrawal.

N. Effects on the Nation's Energy Supply (E.O. 13211)

This rule is not a significant energy action under the definition of that term in E.O. 13211 because:

1. It is not likely to have a significant adverse effect on the supply, distribution or use of energy; and

2. It has not been designated as a significant energy action by the Administrator of OIRA.

Thus, a Statement of Energy Effects is not required.

Due to the inherent practical difficulties of exploration and production in the Arctic, to date there has been minimal exploration activity, and very little production of oil and gas, on the Arctic OCS. The only existing oil production from the Arctic OCS is through the Northstar Island facility in State of Alaska waters.

The regulations' cumulative effects (including baseline provisions) are not expected to affect long-term activity. This regulation establishes specific guidelines that protect the Arctic environment and makes explicit the requirements that operators will face. Protecting the Arctic region from a catastrophic oil spill is imperative for the long-term hydrocarbon development of the region.

We note that, although the rule might have a short-term impact on Arctic OCS exploration and development, other factors over which BOEM and BSEE have no control are likely to have a much greater effect on the rate of oil production from the Arctic OCS region. The primary external factor is the market price of oil and gas. The pace of exploration and development responds to changes in oil prices, with the pace slowing down when prices are decreasing and the pace accelerating when prices are rising.

The Arctic region of Alaska has not previously relied on the type of offshore drilling regulated by this final rule for economic development or well-being. The OCSLA states that the policy of the U.S. is both to make the OCS available for production and development as well as to ensure that operations are conducted safely. Lessees, particularly in the Arctic, obtain OCS leases and pursue exploration with a full understanding of this dynamic. This rulemaking reflects the Bureaus' reasonable and appropriate fulfillment of their multifaceted OCSLA mandates.

O. Clarity of This Regulation

We are required by E.O. 12866, E.O. 12988, and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must:

1. Be logically organized;

2. Use the active voice to address readers directly;

3. Use clear language rather than jargon;

4. Be divided into short sections and sentences; and

5. Use lists and tables wherever possible.

List of Subjects

30 CFR Part 250

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Incorporation

[50] Treasury and General Government Appropriations Act for Fiscal Year 2001, sec. 515 (Pub. L. 106–554) (Dec. 21, 2000).

[51] See OMB regulations at 5 CFR part 1320, *Controlling Paperwork Burdens on the Public.*

by reference, Investigations, Government contracts, Oil and gas exploration, Penalties, Pipelines, Reporting and recordkeeping requirements, Sulfur.

30 CFR Part 254

Continental shelf, Environmental protection, Intergovernmental relations, Oil and gas exploration, Oil pollution, Pipelines, Reporting and recordkeeping requirements.

30 CFR Part 550

Administrative practice and procedure, Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Oil and gas exploration, Penalties, Pipelines, Reporting and recordkeeping requirements, Sulfur.

Dated: June 28, 2016.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, BOEM and BSEE amend 30 CFR parts 250, 254, and 550 as follows:

Title 30—Mineral Resources

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

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

■ 1. The authority citation for 30 CFR part 250 is revised 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 § 250.105 by:

■ a. Revising the definition of ''District Manager''; and

■ b. Adding definitions for ''Arctic OCS'', ''Arctic OCS conditions'', ''Cap and flow system'', ''Capping stack'', ''Containment dome'', and ''Source control and containment equipment (SCCE)'' in alphabetical order.

The revision and additions read as follows:

§ 250.105 Definitions.

* * * * *

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

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

* * * * *

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

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

* * * * *

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

* * * * *

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

* * * * *

Source control and containment equipment (SCCE) means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels the collective purpose of which is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. ''Surface devices'' refers to equipment mounted or staged on a barge, vessel, or facility to separate, treat, store and/or dispose of fluids conveyed to the surface by the cap and flow system or the containment dome. ''Subsea devices'' includes, but is not limited to, remotely operated vehicles, anchors, buoyancy equipment, connectors, cameras, controls and other subsea equipment necessary to facilitate the deployment, operation, and retrieval of the SCCE. The SCCE does not include a blowout preventer.

* * * * *

■ 3. Amend § 250.188 by adding paragraph (c) to read as follows:

§ 250.188 What incidents must I report to BSEE and when must I report them?

* * * * *

(c) On the Arctic OCS, in addition to the requirements of paragraphs (a) and (b) of this section, you must provide to the BSEE inspector on location, if one is present, or to the Regional Supervisor, both of the following:

(1) An immediate oral report if any of the following occur:

(i) Any sea ice movement or condition that has the potential to affect your operation or trigger ice management activities;

(ii) The start and termination of ice management activities; or

(iii) Any ''kicks'' or operational issues that are unexpected and could result in the loss of well control.

(2) Within 24 hours after completing ice management activities, a written report of such activities that conforms to the content requirements in § 250.190.

■ 4. Amend § 250.198 by adding paragraph (h)(95) to read as follows:

§ 250.198 Documents incorporated by reference.

* * * * *

(h) * * *

(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);

* * * * *

■ 5. Amend § 250.300 by revising paragraphs (b)(1) and (2) to read as follows:

§ 250.300 Pollution prevention.

* * * * *

(b)(1) The District Manager may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Manager may also restrict the use of components that could cause unreasonable degradation to the marine environment. No petroleum-based substances, including diesel fuel, may

be added to the drilling mud system without prior approval of the District Manager. For Arctic OCS exploratory drilling, you must capture all petroleum-based mud to prevent its discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all water-based mud from operations after completion of the hole for the conductor casing to prevent its discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged mud may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged mud may adversely affect marine mammals, fish, or their habitat.

(2) You must obtain approval from the District Manager of the method you plan to use to dispose of drill cuttings, sand, and other well solids. For Arctic OCS exploratory drilling, you must capture all cuttings from operations that utilize petroleum-based mud to prevent their discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all cuttings from operations that utilize water-based mud after completion of the hole for the conductor casing to prevent their discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged cuttings may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged cuttings may adversely affect marine mammals, fish, or their habitat.

* * * * *

■ 6. Amend § 250.418 by adding paragraph (j) to read as follows:

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

* * * * *

(j) For Arctic OCS exploratory drilling operations, you must provide the information required by § 250.470.

■ 7. Add § 250.452 to read as follows:

§ 250.452 What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations?

(a) When conducting exploratory drilling operations on the Arctic OCS, you must gather and monitor real-time data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling systems on the rig; and

(3) The well's downhole conditions as monitored by a downhole sensing system, when such a system is installed.

(b) During well operations, you must transmit the data identified in paragraph (a) of this section as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After well operations, you must store the data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must provide BSEE with access to your real-time monitoring data onshore upon request.

■ 8. Add an undesignated center heading and §§ 250.470 through 250.473 to subpart D to read as follows:

Additional Arctic OCS Requirements

§ 250.470 What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?

In addition to complying with all other applicable requirements included in this part, you must provide with your APD all of the following information pertaining to your proposed Arctic OCS exploratory drilling:

(a) A detailed description of:

(1) The environmental, meteorological, and oceanic conditions you expect to encounter at the well site(s);

(2) How you will prepare your equipment, materials, and drilling unit for service in the conditions identified in paragraph (a)(1) of this section, and how your drilling unit will be in compliance with the requirements of § 250.713.

(b) A detailed description of all operations necessary in Arctic OCS conditions to transition the rig from being under way to conducting drilling operations and from ending drilling operations to being under way, as well as any anticipated repair and maintenance plans for the drilling unit and equipment. You should include, among other things, a description of how you plan to:

(1) Recover the subsea equipment, including the marine riser and the lower marine riser package;

(2) Recover the BOP;

(3) Recover the auxiliary sub-sea controls and template;

(4) Lay down the drill pipe and secure the drill pipe and marine riser;

(5) Secure the drilling equipment;

(6) Transfer the fluids for transport or disposal;

(7) Secure ancillary equipment like the draw works and lines;

(8) Refuel or transfer fuel;

(9) Offload waste;

(10) Recover the Remotely Operated Vehicles;

(11) Pick up the oil spill prevention booms and equipment; and

(12) Offload the drilling crew.

(c) A description of well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well, including but not limited to the following:

(1) When you will spud the particular well (*i.e.,* begin drilling operations at the well site) identified in the APD;

(2) How long you will take to drill the well;

(3) Anticipated depths and geologic targets, with timelines;

(4) When you expect to set and cement each string of casing;

(5) When and how you would log the well;

(6) Your plans to test the well;

(7) When and how you intend to abandon the well, including specifically addressing your plans for how to move the rig off location and how you will meet the requirements of § 250.720(c);

(8) A description of what equipment and vessels will be involved in the process of temporarily abandoning the well due to ice; and

(9) An explanation of how you will integrate these elements into your overall program.

(d) A detailed description of your weather and ice forecasting capability for all phases of the drilling operation, including:

(1) How you will ensure your continuous awareness of potential weather and ice hazards at, and during transition between, wells;

(2) Your plans for managing ice hazards and responding to weather events; and

(3) Verification that you have the capabilities described in your BOEM-approved EP.

(e) A detailed description of how you will comply with the requirements of § 250.472.

(f) A statement that you own, or have a contract with a provider for, source control and containment equipment (SCCE), which is capable of controlling and/or containing a worst case discharge, as described in your BOEM-approved EP, when proposing to use a MODU to conduct exploratory drilling operations on the Arctic OCS. The following information must be included in your SCCE submittal:

(1) A detailed description of your or your contractor's SCCE capability to stop or contain flow from an out-of-control well, including your operating assumptions and limitations; your access to and ability to deploy, in accordance with § 250.471, all necessary SCCE; and your ability to evaluate the performance of the well design to determine how you can achieve a full shut-in without having reservoir fluids discharged into the environment;

(2) An inventory of the local and regional SCCE, supplies, and services that you own or for which you have a contract with a provider. You must identify each supplier of such equipment and services and provide their locations and telephone numbers;

(3) Where applicable, proof of contracts or membership agreements with cooperatives, service providers, or other contractors who will provide you with the necessary SCCE or related supplies and services if you do not possess them. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour per day basis while you are drilling below or working below the surface casing;

(4) A detailed description of the procedures you plan to use to inspect, test, and maintain your SCCE; and

(5) A detailed description of your plan to ensure that all members of your operating team, who are responsible for operating the SCCE, have received the necessary training to deploy and operate such equipment in Arctic OCS conditions and demonstrate ongoing proficiency in source control operations. You must also identify and include the dates of prior and planned training.

(g) Where it does not conflict with other requirements of this subpart, and except as provided in paragraphs (g)(1) through (11) of this section, you must comply with the requirements of API RP 2N, Third Edition ''Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions'' (incorporated by reference as specified in § 250.198), and provide a detailed description of how you will utilize the best practices included in API RP 2N during your exploratory drilling operations. You are not required to incorporate the following sections of API RP 2N into your drilling operations:

(1) Sections 6.6.3 through 6.6.4;

(2) The foundation recommendations in Section 8.4;

(3) Section 9.6;

(4) The recommendations for permanently moored systems in Section 9.7;

(5) The recommendations for pile foundations in Section 9.10;

(6) Section 12;

(7) Section 13.2.1;

(8) Sections 13.8.1.1, 13.8.2.1, 13.8.2.2, 13.8.2.4 through 13.8.2.7;

(9) Sections 13.9.1, 13.9.2, 13.9.4 through 13.9.8;

(10) Sections 14 through 16; and

(11) Section 18.

§ 250.471 What are the requirements for Arctic OCS source control and containment?

You must meet the following requirements for all exploration wells drilled on the Arctic OCS:

(a) If you use a MODU when drilling below or working below the surface casing, you must have access to the following SCCE capable of stopping or capturing the flow of an out-of-control well:

(1) A capping stack, positioned to ensure that it will arrive at the well location within 24 hours after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section;

(2) A cap and flow system, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The cap and flow system must be designed to capture at least the amount of hydrocarbons equivalent to the calculated worst case discharge rate referenced in your BOEM-approved EP; and

(3) A containment dome, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The containment dome must have the capacity to pump fluids without relying on buoyancy.

(b) You must conduct a monthly stump test of dry-stored capping stacks. If you use a pre-positioned capping stack, you must conduct a stump test prior to each installation on each well.

(c) As required by § 250.465(a), if you propose to change your well design, you must submit an APM. For Arctic OCS operations, your APM must include a reevaluation of your SCCE capabilities for any new Worst Case Discharge (WCD) rate, and a demonstration that your SCCE capabilities will meet the criteria in § 250.470(f) under the changed well design.

(d) You must conduct tests or exercises of your SCCE, including deployment of your SCCE, when directed by the Regional Supervisor.

(e) You must maintain records pertaining to testing, inspection, and maintenance of your SCCE for at least 10 years and make the records available to any authorized BSEE representative upon request.

(f) You must maintain records pertaining to the use of your SCCE during testing, training, and deployment activities for at least 3 years and make the records available to any authorized BSEE representative upon request.

(g) Upon a loss of well control, you must initiate transit of all SCCE identified in paragraph (a) of this section to the well.

(h) You must deploy and use SCCE when directed by the Regional Supervisor.

(i) Operators may request approval of alternate procedures or equipment to the SCCE requirements of subparagraph (a) of this section in accordance with § 250.141. The operator must show and document that the alternate procedures or equipment will provide a level of safety and environmental protection that will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well.

§ 250.472 What are the relief rig requirements for the Arctic OCS?

(a) In the event of a loss of well control, the Regional Supervisor may direct you to drill a relief well using the relief rig able to kill and permanently plug an out-of-control well as described in your APD. Your relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.

(b) When you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations, you must have access to a relief rig, different from your primary drilling rig, staged in a location such that it can arrive on site, drill a relief

well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control.

(c) Operators may request approval of alternative compliance measures to the relief rig requirement in accordance with § 250.141. The operator must show and document that the alternate compliance measure will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate compliance measure will be able to kill and permanently plug an out-of-control well.

§ 250.473 What must I do to protect health, safety, property, and the environment while operating on the Arctic OCS?

In addition to the requirements set forth in § 250.107, when conducting exploratory drilling operations on the Arctic OCS, you must protect health, safety, property, and the environment by using the following:

(a) Equipment and materials that are rated or de-rated for service under conditions that can be reasonably expected during your operations; and

(b) Measures to address human factors associated with weather conditions that can be reasonably expected during your operations including, but not limited to, provision of proper attire and equipment, construction of protected work spaces, and management of shifts.

■ 9. Amend § 250.720 by adding paragraph (c) to read as follows:

§ 250.720 When and how must I secure a well?

* * * * *

(c) For Arctic OCS exploratory drilling operations, in addition to the requirements of paragraphs (a) and (b) of this section:

(1) If you move your drilling rig off a well prior to completion or permanent abandonment, you must ensure that any equipment left on, near, or in a wellbore that has penetrated below the surface casing is positioned in a manner to:

(i) Protect the well head; and

(ii) Prevent or minimize the likelihood of compromising the down-hole integrity of the well or the effectiveness of the well plugs.

(2) In areas of ice scour you must use a well mudline cellar or an equivalent means of minimizing the risk of damage to the well head and wellbore. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection provided by a mudline cellar if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks.

■ 10. Amend § 250.1920 by:

■ a. Adding a sentence at the end of paragraphs (b)(5), (c), and (d); and

■ b. Adding paragraphs (f) and (g).

The additions read as follows:

§ 250.1920 What are the auditing requirements for my SEMS program?

* * * * *

(b) * * *

(5) * * * For exploratory drilling operations taking place on the Arctic OCS, you must conduct an audit, consisting of an onshore portion and an offshore portion, including all related infrastructure, once per year for every year in which drilling is conducted.

* * * * *

(c) * * * For exploratory drilling operations taking place on the Arctic OCS, you must submit an audit report of the audit findings, observations, deficiencies and conclusions for the onshore portion of your audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(d) * * * For exploratory drilling operations taking place on the Arctic OCS, you must provide BSEE with a copy of your CAP for addressing deficiencies or nonconformities identified in the onshore portion of the audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

* * * * *

(f) For exploratory drilling operations taking place on the Arctic OCS, during the offshore portion of each audit, 100 percent of the facilities operated must be audited while drilling activities are underway. You must start and close the offshore portion of the audit for each facility within 30 days after the first spudding of the well or entry into an existing wellbore for any purpose from that facility.

(g) For exploratory drilling operations taking place on the Arctic OCS, if BSEE determines that the CAP or progress toward implementing the CAP is not satisfactory, BSEE may order you to shut down all or part of your operations.

PART 254—OIL-SPILL RESPONSE REQUIREMENTS FOR FACILITIES LOCATED SEAWARD OF THE COAST LINE

■ 11. The authority citation for 30 CFR part 254 continues to read as follows:

Authority: 33 U.S.C. 1321.

■ 12. Amend § 254.6 by:

■ a. Revising the definition of ''Adverse weather conditions;'' and

■ b. Adding definitions for ''Arctic OCS'' and ''Ice intervention practices'' in alphabetical order.

The revision and additions read as follows:

§ 254.6 Definitions.

* * * * *

Adverse weather conditions means, for the purposes of this part, weather conditions found in the operating area that make it difficult for response equipment and personnel to clean up or remove spilled oil or hazardous substances. These conditions include, but are not limited to: fog, inhospitable water and air temperatures, wind, sea ice, extreme cold, freezing spray, snow, currents, sea states, and extended periods of low light. Adverse weather conditions do not refer to conditions under which it would be dangerous or impossible to respond to a spill, such as a hurricane.

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

* * * * *

Ice intervention practices mean the equipment, vessels, and procedures used to increase oil encounter rates and the effectiveness of spill response techniques and equipment when sea ice is present.

* * * * *

■ 13. Add § 254.55 to subpart D to read as follows:

§ 254.55 Spill response plans for facilities located in Alaska State waters seaward of the coast line in the Chukchi and Beaufort Seas.

Response plans for facilities conducting exploratory drilling operations from a MODU seaward of the coast line in Alaska State waters in the Chukchi and Beaufort Seas must follow the requirements contained within subpart E of this part, in addition to the other requirements of this subpart. Such response plans must address how the source control procedures selected to comply with State law will be integrated into the planning, training, and exercise requirements of §§ 254.70(a), 254.90(a), and 254.90(c), in the event that the proposed operations do not incorporate the capping stack, cap and flow system, containment dome, and/or other similar subsea and surface devices and

equipment and vessels referenced in those sections.

■ 14. Add subpart E to read as follows:

Subpart E—Oil-Spill Response Requirements for Facilities Located on the Arctic OCS

Sec.
254.65 Purpose.
254.66 through 254.69 [Reserved]
254.70 What are the additional requirements for facilities conducting exploratory drilling from a MODU on the Arctic OCS?
254.71 through 254.79 [Reserved]
254.80 What additional information must I include in the ''Emergency response action plan'' section for facilities conducting exploratory drilling from a MODU on the Arctic OCS?
254.81 through 254.89 [Reserved]
254.90 What are the additional requirements for exercises of your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

Subpart E—Oil-Spill Response Requirements for Facilities Located on the Arctic OCS

§ 254.65 Purpose.

This subpart describes the additional requirements for preparing OSRPs and maintaining oil spill preparedness for facilities conducting exploratory drilling operations from a mobile offshore drilling unit (MODU) on the Arctic OCS.

§§ 254.66 through 254.69 [Reserved]

§ 254.70 What are the additional requirements for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to meeting the applicable requirements of this part, your OSRP must:

(a) Describe how the relevant personnel, equipment, materials, and support vessels associated with the capping stack, cap and flow system, containment dome, and other similar subsea and surface devices and equipment and vessels will be integrated into oil spill response incident action planning;

(b) Describe how you will address human factors, such as cold stress and cold related conditions, associated with oil spill response activities in adverse weather conditions and their impacts on decision-making and health and safety; and

(c) Undergo plan-holder review prior to handling, storing, or transporting oil in connection with seasonal exploratory drilling activities, and all resulting modifications must be submitted to the Regional Supervisor. If this review does not result in modifications, you must inform the Regional Supervisor in writing that there are no changes. The requirements of this paragraph (c) are in lieu of the requirements in § 254.30(a).

§§ 254.71 through 254.79 [Reserved]

§ 254.80 What additional information must I include in the ''Emergency response action plan'' section for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to the requirements in § 254.23, you must include the following information in the emergency response action plan section of your OSRP:

(a) A description of your ice intervention practices and how they will improve the effectiveness of the oil spill response options and strategies that are listed in your OSRP in the presence of sea ice. When developing the ice intervention practices for your OSRP, you must consider, at a minimum, the use of specialized tactics, modified response equipment, ice management assist vessels, and technologies for the identification, tracking, containment and removal of oil in ice.

(b) On areas of the Arctic OCS where a planned shore-based response would not satisfy § 254.1(a):

(1) A list of all resources required to ensure an effective offshore-based response capable of operating in adverse weather conditions. This list must include a description of how you will ensure the shortest possible transit times, including but not limited to establishing an offshore resource management capability (*e.g.,* sea-based staging, maintenance, and berthing logistics); and

(2) A list and description of logistics resupply chains, including waste management, that effectively factor in the remote and limited infrastructure that exists in the Arctic and ensure you can adequately sustain all oil spill response activities for the duration of the response. The components of the logistics supply chain include, but are not limited to:

(i) Personnel and equipment transport services;

(ii) Airfields and types of aircraft that can be supported;

(iii) Capabilities to mobilize supplies (*e.g.,* response equipment, fuel, food, fresh water) and personnel to the response sites;

(iv) Onshore staging areas, storage areas that may be used en-route to staging areas, and camp facilities to support response personnel conducting offshore, nearshore and shoreline response; and

(v) Management of recovered fluid and contaminated debris and response materials (*e.g.,* oiled sorbents), as well as waste streams generated at offshore and on-shore support facilities (*e.g.,* sewage, food, and medical).

(c) A description of the system you will use to maintain real-time location tracking for all response resources while operating, transiting, or staging/maintaining such resources during a spill response.

§§ 254.81 through 254.89 [Reserved]

§ 254.90 What are the additional requirements for exercises of your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to the requirements in § 254.42, the following requirements apply to exercises for your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS:

(a) You must incorporate the personnel, materials, and equipment identified in § 254.70(a), the safe working practices identified in § 254.70(b), the ice intervention practices described in § 254.80(a), the offshore-based response requirements in § 254.80(b), and the resource tracking requirements in § 254.80(c) into your spill-response training and exercise activities.

(b) For each season in which you plan to conduct exploratory drilling operations from a MODU on the Arctic OCS, you must notify the Regional Supervisor 60 days prior to handling, storing, or transporting oil.

(c) After the Regional Supervisor receives notice pursuant to § 254.90(b), the Regional Supervisor may direct you to deploy and operate your spill response equipment and/or your capping stack, cap and flow system, and containment dome, and other similar subsea and surface devices and equipment and vessels, as part of announced or unannounced exercises or compliance inspections. For the purposes of this section, spill response equipment does not include the use of blowout preventers, diverters, heavy weight mud to kill the well, relief wells, or other similar conventional well control options.

CHAPTER V—BUREAU OF OCEAN ENERGY MANAGEMENT, DEPARTMENT OF THE INTERIOR

PART 550—OIL AND GAS AND SULFUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 15. The authority citation for 30 CFR part 550 is revised to read as follows:

Authority: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

■ 16. Amend § 550.105 by adding definitions for ''Arctic OCS'' and ''Arctic OCS conditions'' in alphabetical order to read as follows:

§ 550.105 Definitions.

* * * * *

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

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

* * * * *

■ 17. Amend § 550.200 in paragraph (a) by adding the term ''IOP'' in alphabetical order:

§ 550.200 Definitions.

* * * * *

(a) * * *

IOP means Integrated Operations Plan.

* * * * *

■ 18. Add § 550.204 to read as follows:

§ 550.204 When must I submit my IOP for proposed Arctic exploratory drilling operations and what must the IOP include?

If you propose exploratory drilling activities on the Arctic OCS, you must submit an Integrated Operations Plan (IOP) to the Regional Supervisor at least 90 days prior to filing your EP. Your IOP must describe how your exploratory drilling program will be designed and conducted in an integrated manner that accounts for Arctic OCS conditions and include the following information:

(a) A description of how all vessels and equipment will be designed, built, and/or modified to account for Arctic OCS conditions;

(b) A schedule of your exploratory drilling program, including contractor work on critical components of your program;

(c) A description of your mobilization and demobilization operations, including tow plans that account for Arctic OCS conditions, as well as your general maintenance schedule for vessels and equipment;

(d) A description of your exploratory drilling program objectives and timelines for each objective, including general plans for abandonment of the well(s), such as:

(1) Contingency plans for temporary abandonment in the event of ice encroachment at the drill site;

(2) Plans for permanent abandonment; and

(3) Plans for temporary seasonal abandonment.

(e) A description of your weather and ice forecasting capabilities for all phases of the exploration program, including a description of how you would respond to and manage ice hazards and weather events;

(f) A description of work to be performed by contractors supporting your exploration drilling program (including mobilization and demobilization), including:

(1) How such work will be designed or modified to account for Arctic OCS conditions; and

(2) Your concepts for contractor management, oversight, and risk management.

(g) A description of how you will ensure operational safety while working in Arctic OCS conditions, including but not limited to:

(1) The safety principles that you intend to apply to yourself and your contractors;

(2) The accountability structure within your organization for implementing such principles;

(3) How you will communicate such principles to your employees and contractors; and

(4) How you will determine successful implementation of such principles.

(h) Information regarding your preparations and plans for staging of oil spill response assets;

(i) A description of your efforts to minimize impacts of your exploratory drilling operations on local community infrastructure, including but not limited to housing, energy supplies, and services; and

(j) A description of whether and to what extent your project will rely on local community workforce and spill cleanup response capacity.

■ 19. Revise § 550.206 to read as follows:

§ 550.206 How do I submit the IOP, EP, DPP, or DOCD?

(a) *Number of copies.* When you submit an IOP, EP, DPP, or DOCD to BOEM, you must provide:

(1) Four copies that contain all required information (proprietary copies);

(2) Eight copies for public distribution (public information copies) that omit information that you assert is exempt from disclosure under the Freedom of Information Act (FOIA) (5 U.S.C. 552) and the implementing regulations (43 CFR part 2); and

(3) Any additional copies that may be necessary to facilitate review of the IOP, EP, DPP, or DOCD by certain affected States and other reviewing entities.

(b) *Electronic submission.* You may submit part or all of your IOP, EP, DPP, or DOCD and its accompanying information electronically. If you prefer to submit your IOP, EP, DPP, or DOCD electronically, ask the Regional Supervisor for further guidance.

(c) *Withdrawal after submission.* You may withdraw your proposed IOP, EP, DPP, or DOCD at any time for any reason. Notify the appropriate BOEM OCS Region if you do.

■ 20. Amend § 550.220 by revising paragraph (a) and adding paragraph (c) to read as follows:

§ 550.220 If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?

* * * * *

(a) *Emergency plans.* A description of your emergency plans to respond to a fire, explosion, personnel evacuation, or loss of well control, as well as a loss or disablement of a drilling unit, and loss of or damage to a support vessel, offshore vehicle, or aircraft.

* * * * *

(c) If you propose exploration activities on the Arctic OCS, the following planning information must also accompany your EP:

(1) *Suitability for Arctic OCS conditions.* A description of how your exploratory drilling activities will be designed and conducted in a manner that accounts for Arctic OCS conditions and how such activities will be managed and overseen as an integrated endeavor.

(2) *Ice and weather management.* A description of your weather and ice forecasting and management plans for all phases of your exploratory drilling activities, including:

(i) A description of how you will respond to and manage ice hazards and weather events;

(ii) Your ice and weather alert procedures;

(iii) Your procedures and thresholds for activating your ice and weather management system(s); and

(iv) Confirmation that you will operate ice and weather management

and alert systems continuously throughout the planned operations, including mobilization and demobilization operations to and from the Arctic OCS.

(3) *Source control and containment equipment capabilities.* A general description of how you will comply with § 250.471 of this title.

(4) *Deployment of a relief well rig.* A general description of how you will comply with § 250.472 of this title, including a description of the relief well rig, the anticipated staging area of the relief well rig, an estimate of the time it would take for the relief well rig to arrive at the site of a loss of well control, how you would drill a relief well if necessary, and the approximate timeframe to complete relief well operations.

(5) *Resource-sharing.* Any agreements you have with third parties for the sharing of assets or the provision of mutual aid in the event of an oil spill or other emergency.

(6) *Anticipated end of seasonal operations dates.* Your projected end of season dates, and the information used to identify those dates, for:

(i) The completion of on-site operations, which is contingent upon your capability in terms of equipment and procedures to manage and mitigate risks associated with Arctic OCS conditions; and

(ii) The termination of drilling operations consistent with the relief rig planning requirements under § 250.472 of this title and with your estimated timeframe under paragraph (c)(4) of this section for completion of relief well operations.

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