Oil and Gas and Sulphur Operations on the Outer Continental Shelf – Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf

Final Regulatory Impact Analysis

RIN: 1082-AA00

FINAL RULE

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

(30 CFR Parts 250 and 254)

Bureau of Ocean Energy Management

(30 CFR Part 550)

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Abbreviations

APD	Application for Permit to Drill
API	American Petroleum Institute
API RP	American Petroleum Institute Recommended Practice
BBLs	Barrels
BLS	Bureau of Labor Statistics
BOEM	Bureau of Ocean Energy Management
BOP	Blowout preventer
BSEE	Bureau of Safety and Environmental Enforcement
DOI	Department of the Interior
EO	Executive Order
EP	Exploration Plan
GOM	Gulf of Mexico
IOP	Integrated Operations Plan
MODU	Mobile Offshore Drilling Unit
NTL	Notice to Lessees
OCS	Outer Continental Shelf
OMB	Office of Management and Budget
OSRP	Oil Spill Response Plan
PPCS	Pre-positioned capping stack
RIA	Regulatory Impact Analysis
SCCE	Source Control and Containment Equipment
SEMS	Safety and Environmental Management Systems
UMRA	Unfunded Mandates Reform Act of 1995

1. Executive Summary

Before authorizing exploration drilling for Arctic OCS hydrocarbon resources, BOEM and BSEE must ensure that exploration can occur safely and with minimal environmental risk. This regulation provides a regulatory framework specifically designed for Arctic OCS exploration and outlines the specific requirements for exploratory drilling activities. Its purpose is to provide the requirements and standards to which all individual exploration plans, permits and operations will be held.

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.[1] However, because the potential adverse effects of a catastrophic oil spill are so large, steps must be taken to reduce the spill risk, duration, and severity should one occur. BOEM and BSEE have determined that the benefits of this rule exceed the costs when both quantitative and qualitative factors are considered.

1.1 Compliance Costs

The new provisions of the rule are estimated to result in compliance costs of $2,047.6 million under 3-percent discounting and $1,739.0 million under 7-percent discounting over 10 years.[2] Exhibit 1 shows the provisions of the rule and the primary benefits. As the exhibit emphasizes, many of the 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.

[1] "Catastrophic event" is defined in our analysis consistent with the Draft Economic Analysis Methodology for the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program, as "any high-volume, long-duration oil spill from a well blow-out, regardless of its cause (e.g., a hurricane, human error, terrorism)."

[2] For the final rule, based on the recent relinquishment and termination of many Chukchi and Beaufort Sea planning areas leases, BOEM and BSEE use a 10 numbered year scenario with active exploratory drilling running 9 years (year 2 to year 10). This is a conservative approach, as BOEM and BSEE do not anticipate any active open water exploratory drilling in the next several years. The use of a numbered year scenario rather than calendar year scenario reflects the significant uncertainty regarding when additional future Arctic exploration will commence.

Exhibit 1. Regulatory Provisions, Costs, and Benefits[3]

Provision	Primary Benefit	Final RIA Rule Cost Discounted at 3% over 10 years $ millions
(a) Additional Incident Reporting Requirements	Improves information to Federal agencies	$0.56
(b) Additional Pollution Prevention Requirements	Minimizes natural resource impacts	$141.09
(c) Additional Requirements for Securing Wells	Reduces risk of a spill	*
(d) Real-time Monitoring Requirements	Reduces risk of a spill	**
(e) Additional Information Requirements for APDs	Improves information to Federal agencies	$0.23
(f) Incorporation of API RP 2N	Reduces risk of a spill	$0.08
(g) Additional SCCE Requirements	Improves spill control and containment	$681.92
(h) Relief Rig Requirements	Improves control of a spill	$1,206.55
(i) Additional Auditing Requirements	Improves information to Federal agencies	$5.58
(j) Real-time Location Tracking Requirements	Improves information to Federal agencies	$0.96
(k) IOP Requirements	Improves coordination among Federal agencies	$7.67
(l) Planning Information Requirements to Accompany EPs	Improves information to Federal agencies	$2.57
(m) Industry Familiarization with Rule	General	$0.37
Total:		$2,047.60

** 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 BSEE Well Control rule at § 250.724 requires real-time monitoring for all operations with a subsea BOP or surface BOP on a floating facility, thus the cost for this provision is assigned to the regulatory baseline.*

[3] Note that former provision (d) from the NPRM: Stipulating the frequency of blowout preventer pressure tests, was removed from this rule. These requirements were addressed in the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking.

1.2 Benefits

BOEM and BSEE recognize that the Arctic OCS contains substantial oil and natural gas resources, and this rule provides the guidance and requirements that operators must follow to minimize the risks of catastrophic oil spills when exploring for these valuable resources. Although this RIA focuses its discussion on the benefits of reducing the probability, duration, or severity of a catastrophic oil spill, BOEM and BSEE recognize that similar benefits relate, perhaps to a lesser extent, to any significant but non-catastrophic oil spills as well. The unique nature of the Arctic, its ecological resources, and the Alaska Natives' subsistence needs make the rule even more necessary to avoid the devastating effects of a catastrophic oil spill. Although the probability of a catastrophic spill is very small, the *Deepwater Horizon* oil spill demonstrated that such low probability events can have devastating human, economic, and environmental consequences.

Due to both the uncertainty and difficulty of measuring benefits, we do not offer an aggregate quantitative assessment of all of the rulemaking 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, (2) minimizing natural resource impacts, (3) reducing the risk of a catastrophic oil spill, and (4) improving containment and reducing the severity of a catastrophic oil spill. Each of these benefits is discussed in more detail in Section 7.2 of this final RIA. In addition to these four main benefits of the rule's individual provisions, in aggregate the rule has additional benefits including the provision of regulatory certainty to industry and the assurance to stakeholders and partners that the Department of the Interior (DOI) is committed to safe Arctic OCS operations.

1.2.1 Benefit: Improving Information and Coordination among Federal Agencies

A portion of the rule's new provisions are designed to improve Federal interagency coordination of Arctic exploratory activities. Improved information provided to Federal agencies will facilitate coordination within the federal family and enable agencies to better identify risk mitigations early in the planning process. These benefits are discussed qualitatively in Section 7.2.1.

1.2.2 Benefit: Minimizing Natural Resource and Subsistence Impacts

One provision of the rule is designed specifically to minimize natural resource and subsistence impacts of exploratory activities, outside the context of a catastrophic spill. The benefits of this provision are discussed in Section 7.2.2. Of course, the provisions to reduce the risk and duration of a catastrophic oil spill also minimize natural resource impacts, but these benefits are discussed in sections specifically on catastrophic oil spills.

1.2.3 Benefit: Reducing the Risk of a Catastrophic Oil Spill

As shown in Exhibit 1, the two baseline compliance provisions ((c) Additional Requirements for Securing Wells and (d) Real-time Monitoring Requirements) are designed to reduce the risk of a catastrophic oil spill. The benefits of the rule's new provision which is designed to reduce the risk of a spill ((f) Incorporation of API RP 2N) are discussed in Section 7.2.3 and the benefits of relevant baseline provisions are discussed in the Appendix. As discussed, this RIA focuses its discussion on the benefits of reducing the probability, duration, or severity of a catastrophic oil spill; however, it is possible that some of the rule's provisions can also reduce the risk, perhaps to a lesser extent, of any significant but non-catastrophic oil spills as well.

1.2.4 Benefit: Reducing the Duration or Severity of a Catastrophic Oil Spill

Provisions of this rule are designed to ensure that equipment and personnel are readily available to respond to a loss of well control event. To compare the benefit of reducing the duration or severity of a catastrophic oil spill with the costs incurred, this RIA considers the benefits of the rule as potential avoided costs from the reduced duration or severity of an oil spill.

1.2.5 Benefit: Regulatory Certainty to Industry

This rule provides a holistic regulatory structure for OCS exploration activities in the Arctic. The provisions in this rule codify existing requirements in the Arctic designed to reduce the probability of a catastrophic spill or to reduce the impacts of a spill should one occur, improve the information to and coordination among Federal agencies, and minimize natural resource and ecosystem impacts of offshore operations in the Arctic. A benefit of this rule is to provide specific Arctic regulations clearly identifying the requirements for operators to safely explore for hydrocarbons on the Arctic OCS.

One of the key findings of the National Petroleum Council's Arctic Report was the necessity of such clarity. The report stated 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).[4] This rule provides those Arctic-specific regulatory requirements.

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 improved regulatory efficiency. The certainty from the requirements in this rule could facilitate exploration of the Beaufort and Chukchi Sea Planning Areas. 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.[5]

[4] 2015 National Petroleum Council Report to the Secretary of Energy; Arctic Potential, Realizing the Promise of U.S. Arctic Oil and Gas Resources; http://www.npcarcticpotentialreport.org/.
[5] Available at http://www.boem.gov/2016-National-Assessment-Fact-Sheet/

1.2.6 Benefit: Assurance to Stakeholders and Partners

The American public greatly values the Arctic as a pristine, unspoiled environment worthy of protection. Of the approximately one million public comments BOEM received on the 2017-2022 Draft Proposed Program, slightly less than half of the commenters opposed leasing in the Arctic, citing several concerns including, but not limited to, oil spills, disruption to subsistence activities, and habitat destruction. In addition to providing regulatory certainty to industry, another benefit of this rule is to provide assurance to other stakeholders and partners, such as tribes, citizens, and other countries, that the United States will explore the Arctic safely and with the tenets of environmental stewardship at the forefront of the decision making process. This rule builds on one of the themes from the National Petroleum Council's Arctic Report that steps be taken to "secure public confidence" that activities can be conducted safely. In addition, 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 develop operationally safe and environmentally sustainable development. The United States is entering into the Agreement on Cooperation on Marine Oil Pollution Preparedness and Response in the Arctic and must follow certain provisions outlined in Article 4: Systems for Oil Pollution Preparedness and Response.[6] These regulations help provide assurances to the international community that our operators in the Arctic will follow the required preparedness procedures and do everything possible to prevent an oil spill or to minimize the effects, should one occur. Further, the National Petroleum Council's report on the Arctic 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

[6] http://www.state.gov/r/pa/prs/ps/2013/05/209406.htm.

energy resources are developed in a sustainable manner that respects the fragile environment and the interests and cultures of indigenous peoples."[7]

2. Introduction

The U.S. Arctic region, as recognized by the United States and defined in the U.S. Arctic Research and Policy Act of 1984, encompasses an extensive marine and terrestrial area, but this rule focuses solely on the OCS within the Beaufort Sea and Chukchi Sea Planning Areas. 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, reinforce the need to codify measures already occurring in practice for Arctic OCS oil and gas exploratory operations. After considering the input provided by various partners and stakeholders and DOI's direct experience from Shell's 2012 and 2015 Arctic OCS operations, 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 U.S. Arctic OCS is a unique area, and utmost care should be taken when operating in it. Sea ice is a dominant feature in the Arctic that affects the physical, biological, and cultural aspects of life in the area. Given the presence and movement of sea ice, the Arctic OCS is well known for its ice-associated animals (e.g., seals, Pacific walrus, and polar bears). Other Federally protected marine mammals are also present in the area (e.g., bowhead, gray, and beluga whales). The area also serves as a habitat for migrating birds, and the waters provide habitat for 40 species of fish and deep-water coral, which forms the seafloor habitat. Some of the animals in the region are listed or proposed for listing as threatened or endangered under the Endangered Species Act. These species include marine mammals such as the bowhead, humpback, and fin whales, which are endangered, and polar bears, which are threatened. Other endemic

[7] 2015 National Petroleum Council Report to the Secretary of Energy; Arctic Potential, Realizing the Promise of U.S. Arctic Oil and Gas Resources; http://www.npcarcticpotentialreport.org/, executive summary p. 9 (March 2015).

species include three bird species (the spectacled eider and Steller’s eider are threatened, and the yellow-billed loon is a candidate for the endangered species list).[8]

In addition to the unique biological and ecological resources, the region also has unique cultural features. The sparsely populated areas adjacent to the Beaufort and Chukchi Seas primarily include traditional Alaska Native community residents who depend on the natural environment for food and materials, especially the marine environment. A central cultural tradition of these communities is participation in bowhead whale hunts. A recent survey by the Alaska Department of Administration found that more than 25 percent of the respondents living in the U.S. Arctic relied on subsistence hunting and fishing for at least half of their food supply.[9] Given the reliance on marine subsistence, an oil spill in this region could have a major sociocultural impact. Alaska Native communities highly value the cultural amenities related directly to the use of the region. This rule provides safeguards that protect the Alaska Native culture and recognize the importance of their way of life. This recognition is consistent with the U.S. National Arctic Strategy goal to develop the Arctic in consultation and coordination with Alaska Natives. In addition, people outside of Alaska attribute a value to the knowledge that the Alaskan wilderness exists and is pristine, even though they are likely never to go there. Though monetizing these non-use values are difficult because they are not traded in markets and their values are highly subjective, this is an additional consideration when developing precautions to prevent catastrophic oil spills in the region. These non-use values are discussed in more detail in Section 7.2.4.1.1.

From inception to execution to completion, every phase of U.S. Arctic OCS operations comes with inherent challenges and operational risks. BOEM and BSEE have determined that the provisions contained in the final rule are reasonable and necessary to ensure that exploration is conducted responsibly and is subject to the highest safety and environmental standards. The final regulations are

[8] This information is from the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Draft Proposed Program, January 2015, p. 6-4. Some species referenced in this program document may no longer be listed as threatened or endangered.
[9] 2017-2022 Outer Continental Shelf Oil and Gas Leasing Draft Proposed Program p. 4–27.

also necessary to provide clarity and regulatory certainty to industry regarding the requirements that BOEM and BSEE will continue to expect operators to meet in their exploration and drilling programs. Further, the rule provides the certainty to all stakeholders that Arctic operations will be undertaken with the utmost regard for safety and environmental protection.

2.1 Executive Orders and the Unfunded Mandates Reform Act

Changes to Federal regulations must undergo several types of economic analyses. First, EOs 12866 and 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). EO 13563 emphasizes the importance of quantifying costs and benefits, reducing costs, harmonizing rules, considering employment impacts, and promoting flexibility. Under EO 12866, the Office of Management and Budget's Office of Information and Regulatory Affairs (OIRA) must determine whether a regulatory action is significant and, thus, subject to the requirements of the EO and OIRA review. Section 3(f) of EO 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 EO 12866. The costs attributed to the rule are estimated to have an annual effect of at least $100 million. Therefore, OIRA has determined that this rule is economically significant.

This Regulatory Impact Analysis (RIA) addresses requirements under the Unfunded Mandates Reform Act of 1995 (UMRA) and Executive Orders (EOs) 13563 and 12866.

1. We have determined that the rule can be expected to affect operators and holders of Federal oil and gas leases that could conduct exploratory drilling on the Arctic OCS. No small companies hold leases on the Arctic OCS. Previously only one small company with 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.

2. We have determined that the rule will not impose an unfunded mandate on State, local, or tribal governments as defined by the UMRA. The provisions of this rulemaking provide safety and environmental benefits for Arctic OCS exploratory operations. The rule includes requirements that reduce the probability of a catastrophic spill and reduce the duration and severity of a spill, should one occur. Another benefit of the rule is to provide regulatory certainty to industry and assurance to other stakeholders in the Arctic about safety and environmental protection measures that operators will be required to follow.

2.2 Outline of RIA

This RIA focuses on identifying, discussing, and measuring, where possible, the costs and benefits of the different components of the rule. Section 3 describes the need for regulation and Section 4 outlines the alternatives considered. Sections 5 and 6 provide the assumptions used in the analysis, including the definition of the baseline and the cost and exploration scenario assumptions. The assumptions for the final RIA include some changes from the initial RIA. First, 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 is similar, however the beginning year is no longer assumed. The scenario aligns exploration activity with numbered years instead of calendar years. The result is that the bureaus are not estimating when exploration may begin, but rather the possible activity when it does begin. Acknowledging the temporal uncertainty of future Arctic exploration allows the public to focus on the potential compliance costs and benefits of the rule. This approach also provides for maximum potential costs, as the bureaus do not anticipate exploratory activity over the next several years. Second, many of the cost assumptions have been updated based on comments received on the initial RIA. Third, the assumption of costs assigned to the baseline has been revised to more accurately capture current regulatory requirements and industry practice. Fourth, this RIA does not include provisions for more frequent BOP pressure testing. This requirement has been eliminated from this rule and, therefore, its costs and benefits are not discussed in this RIA. Any changes to requirements for BOP pressure tests were included in the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking.

Section 7 of the RIA provides the analysis of costs and benefits of the rule's new provisions. This section outlines the ten new requirements in the regulation and the potential benefits of these requirements. The benefits discussion is largely qualitative, but provides important information on the types of benefits which can be expected from the rule. Section 8 provides a discussion of the non-monetized impacts of the rule. Section 9 provides concluding remarks. Section 10 provides information applicable to the Unfunded Mandates Reform Act. The Appendix provides compliance cost estimates for regulatory provisions assigned to the baseline.

3. Need for Regulation

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 regulation provides a regulatory framework specifically designed for Arctic OCS exploration and outlines the specific requirements for exploratory drilling activities. Its purpose is to provide the requirements and standards to which all individual operations will be held. The National Petroleum Council's Arctic Report 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).[10] This rule provides those Arctic-specific requirements.

Although an oil and gas regulatory program for the Arctic OCS exists, DOI engagement with partners and stakeholders has revealed the need for new and revised regulatory measures for exploratory drilling by floating drilling vessels and jack-up rigs (collectively known as mobile offshore drilling units or MODUs) on the Arctic OCS. The primary provisions in this rule are designed to prevent or mitigate a catastrophic oil spill, which is a low-probability, high-impact event.

The unique Arctic characteristics defined by its remote location and ice season increase the possibility that a loss of well control event could become a catastrophic oil spill. Without certain well control mechanisms required in this rule, a catastrophic oil spill from a loss of well control event could flow hydrocarbons until the next open water season. In particular, the requirement for ready access to SCCE and the requirement that operators be capable of drilling a same season relief well ensure that any loss of well control event can be contained within the same open-water season.

Evaluating with precision the benefits and costs for this rulemaking is especially difficult because the frequency or probability of a loss of well control event with sustained uncontrolled hydrocarbon flow is extremely low. Given the low probability, high consequence nature of catastrophic oil spills, an estimate of the risked costs of a spill in the traditional cost-benefit sense would provide results which mask the severity of a catastrophic oil spill. Nevertheless, because the potential environmental effects from a catastrophic spill are so large, this rulemaking would clearly be cost-beneficial if a high-impact event does occur through provisions of this rule designed to contain and control an oil spill. Because BOEM and BSEE are strongly risk averse to a lessee incurring a catastrophic oil spill, and any attempt to

[10] 2015 National Petroleum Council Report to the Secretary of Energy; Arctic Potential, Realizing the Promise of U.S. Arctic Oil and Gas Resources; http://www.npcarcticpotentialreport.org/.

monetize this risk aversion would be very uncertain, BOEM and BSEE present an estimate of oil spill risk in 7.2.3.1 and an estimate of the aggregate spill costs which are potential benefits in 7.2.4.1.

To explain further, the policy implications of aversion to risk are analogous to the decision to purchase insurance. Most people are willing to purchase insurance at a premium when the potential loss might be a meaningful amount relative to the person's wealth. The insurance industry functions on the premise that individuals typically have a greater aversion for losses compared to gains, and they are profitable because that, generally, is the case – i.e., individuals are collectively willing to invest more in security against meaningful losses than they actually incur in such losses. The potential damages and losses from a loss of well control event in the Arctic can be viewed through a similar prism. BOEM and BSEE are approaching their Arctic regulatory responsibility with a significant aversion to risk of a catastrophic oil spill. BOEM and BSEE, acting in the public interest, have concluded that if an operator decides to drill for hydrocarbons on the Arctic OCS it must adhere to the provisions in this rulemaking, which BOEM and BSEE have determined will provide the necessary protections to reduce the chances of such a spill and mitigate damages if a loss of well control event occurs.

This final rule will provide protections by adding to and revising existing regulations in 30 CFR Parts 250, 254, and 550 for Arctic OCS oil and gas exploration activities that use MODUs and related operations during the Arctic OCS open-water drilling season. 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, SCCE while drilling below, or working below, the surface casing;

(4) Has access to a separate relief rig located so that it could 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 suitable 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 regulation codifies existing practices and specific operating models for the extreme, changing conditions on the Arctic OCS. The regulations require comprehensive planning of operations, especially for emergency response and safety systems, and will further institutionalize a proactive approach to OCS safety. A goal of the final rule is to identify possible vulnerabilities early in the planning process so that corrections can be made to decrease the probability of a safety or environmental incident. The regulatory requirements are designed to ensure that those plans are executed in a safe and in an environmentally protective manner, despite the challenges presented by the Arctic.[11] Exhibit 2 shows the provisions of the rule and their primary purposes. As the exhibit emphasizes, many of the 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.

[11] An alternative for managing risk is to require operators to carry insurance to cover the social costs of a worst-case scenario. Requiring insurance would help address the concern that operators might not be considering the possible societal damages from an oil spill, but would also be hampered by the same impossibility of quantifying and monetizing all of the social, cultural, and environmental costs of a catastrophic spill. Limits of liability and oil spill financial responsibility are governed by OPA 90 as amended and are outside the scope of this rulemaking.

Exhibit 2. Regulatory Provisions and Benefits[12]

Provision	Primary Benefit
(a) Additional Incident Reporting Requirements	Improves information to Federal agencies
(b) Additional Pollution Prevention Requirements	Minimizes natural resource impacts
(c) Additional Requirements for Securing Wells (*baseline*)	Reduces risk of a spill
(d) Real-time Monitoring Requirements (*baseline)*	Reduces risk of a spill
(e) Additional Information Requirements for APDs	Improves information to Federal agencies
(f) Incorporation of API RP 2N	Reduces risk of a spill
(g) Additional SCCE Requirements	Improves control and containment of a spill
(h) Relief Rig Requirements	Improves control of a spill
(i) Additional Auditing Requirements	Improves information to Federal agencies
(j) Real-time Location Tracking Requirements	Improves information to Federal agencies
(k) IOP Requirements	Improves coordination among Federal agencies
(l) Planning Information Requirements to Accompany EPs	Improves information to Federal agencies
(m) Industry Familiarization with the New Rule	General

BOEM and BSEE must ensure that an appropriate effort is made at a regulatory level to promote safety and environmental protection in Arctic OCS operations. If a loss of well control incident occurs and an uncontrolled flow of hydrocarbons results, the response capability required in this rule will enable operators to stop or contain the flow more quickly. This rule is necessary to clarify and provide certainty to regulatory requirements for Arctic exploratory drilling. Additional provisions in this rulemaking will provide BOEM and BSEE and other stakeholders the information necessary to evaluate and be confident in the proposed operations of Arctic OCS operators.

[12] Note that former provision (d): Stipulating the frequency of blowout preventer pressure tests was removed from this rule. These requirements were addressed in the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking.

4. Alternatives

BOEM and BSEE have considered two alternatives for dealing with the safety and environmental concerns raised by exploration activities on the Arctic OCS:

(1) Promulgate the rule changes described in the rule; or

(2) Take no regulatory action and continue to rely on existing oil and gas regulations, industry standards, and operator prudence.

BOEM and BSEE have decided to move forward with this rulemaking, in lieu of taking no regulatory action, because relying on the regulatory status quo would not address the safety and environmental concerns partners and stakeholders in the Arctic region have raised. Further, the regulatory status quo would not provide the same regulatory certainty for operators seeking approval of exploration plans or APDs as this regulation. In addition, the rule will provide for additional Alaska Native cultural and environmental protections.

5. Baseline Assumptions

The baseline is the best assessment of the current conditions for Arctic OCS exploratory operations in the absence of this rulemaking. It represents the current regulatory requirements, industry standards, and operator prudence. Costs associated with certain provisions included in this rule are considered baseline compliance costs because they are similar to, or duplicative of, current regulatory requirements. Thus, the baseline includes impacts resulting from Arctic measures or capital investments that existing regulatory provisions (consistent with clarifications in guidance) require and associated industry standards contain.

The desire of operating companies to increase OCS safety margins—especially in the Arctic—has continued to advance in recent years. In the wake of the *Deepwater Horizon* oil spill, companies have strengthened their measures to avoid blowouts and respond promptly if a loss of well control event occurs. These enhanced safety practices have become standard and are appropriately considered in the regulatory baseline for this rule.

The following provisions are codified in the rule. Each provision is categorized as baseline or a new regulatory requirement.[13]

(a) Additional incident reporting requirements (new);

(b) Additional pollution prevention requirements and clarification of requirements (new);

(c) Additional requirements for securing wells (baseline);

(d) Real-time monitoring requirements (baseline);

(e) Additional information requirements for applications for permit to drill (APDs) (new information requirements);

(f) Incorporation of American Petroleum Institute (API) RP 2N, 3rd Edition (new because compliance information must be submitted);

(g) Additional SCCE requirements (new);

(h) Relief rig requirements (new);

(i) Additional auditing requirements (new);

(j) Real-time location tracking requirements (new);

(k) IOP requirements (new);

(l) Additional requirements for EPs (new); and

(m) Industry familiarization with the rule (new).

After reviewing public comments and the issuance of the final BSEE BOP/Well Control Rule, we determined that two of the provisions that had been assigned as imposing new regulatory compliance

[13] Note that blowout preventer (BOP) pressure testing requirements were included in the proposed rule, but have been removed from this final rule. (Requirements for BOP pressure testing were addressed in the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking).

costs in the proposed rule should be included in the baseline. The regulatory provisions codified in this rulemaking and considered in the regulatory baseline are (c) and (d):

(c) Additional requirements for securing wells (§ 250.720): The current regulation requires, among other things, that operators install a downhole safety device at an appropriate depth whenever drilling operations are interrupted. BSEE is adding a new paragraph (c)(1) requiring exploratory drilling operators on the Arctic OCS to secure any equipment left on, near, or in a temporarily abandoned well that has penetrated below the surface casing in a way that will protect the well head and prevent or minimize the likelihood of compromising of the integrity of the well or plugs. For exploration wells located in an area subject to ice scour, based on a shallow hazards survey, paragraph (c)(2) requires a mudline cellar or equivalent means of protection.

A virtually identical requirement exists in BSEE's current regulations at § 250.451(h), entitled "What must I do in certain situations involving BOP equipment or systems?" Editorial changes were made to § 250.451(h) in 2011, but no substantial changes were made in the mudline cellar requirement for Arctic drilling in ice scour areas. The drilling of mudline cellars has been a longstanding practice in the Chukchi and Beaufort Seas, and therefore this requirement is appropriately included in the regulatory baseline. The existing baseline well cellar requirement from section 250.451(h) is shown in Exhibit 3.

Exhibit 3. Existing Baseline Well Cellar Requirement

If you encounter the following situation:	Then you must . . .
250.451(h) Use a subsea BOP system in an ice-scour area,	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

(d) Real-time Monitoring Requirements (§ 250.452): Section 250.452 outlines real-time monitoring requirements for Arctic OCS exploratory drilling operations. Paragraph (a) includes requirements for real-time data gathering and monitoring capability for data on the BOP control system, the fluid handling systems on the rig, and the well's downhole conditions. Paragraph (b) includes requirements for onshore data transmission, monitoring, storage, and notification and availability to BSEE. These codified requirements result, in part, from recommendations stemming from investigations of the *Deepwater Horizon* oil spill and help improve safety and provide information to Federal agencies.

The initial RIA considered real-time monitoring a compliance cost for the rule. However, real-time monitoring is required under the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking at § 250.724. Therefore, we determined that real-time monitoring cost should be included in the regulatory baseline. BOEM and BSEE acknowledge there may be instances when real-time monitoring could be required under § 250.452 but not under § 250.724. Section 250.724 requires real-time monitoring when conducting well operations with a subsea BOP, with a surface BOP on a floating facility, or when operating in a high-pressure/high temperature (HPHT) environment. Arctic exploratory drilling may be conducted from grounded platforms such as a jack-up rig that do not utilize a subsea BOP. 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). Real-time monitoring was a condition of the approvals for the 2012 and 2015 Shell EPs. Accordingly, beyond the majority of anticipated Arctic exploratory drilling operations already required by the Well Control Rule to have real-time monitoring capabilities, the Bureaus have concluded that real-time monitoring is an industry standard practice for exploratory drilling under challenging Arctic conditions and is therefore properly considered a baseline cost.

To acknowledge the compliance cost estimate for the rule's two provisions included in the baseline, we have provided the estimated monitoring and associated reporting requirements in the baseline cost analysis found in the Appendix.

6. Arctic OCS Economic Analysis Assumptions

We estimated the costs and benefits presented in this document using various data inputs. Some of these data inputs were common to many of the calculations, including the assumptions discussed below about the affected population of operators and drilling operations, wage rates and loaded wage factors, daily rig operating costs, and the burden for BOEM/BSEE to review paperwork submissions. Several public comments received on the proposed rule provided improved cost information. Where deemed appropriate, the compliance cost estimates are updated from the initial RIA to include more accurate duration or cost factors. This section outlines the different cost and scenario assumptions which are used throughout the RIA.

6.1 Cost Assumptions

Section 7.1 (Costs of the Rule's Provisions) describes how we accounted for the likely economic costs of the rule. Each section identifies the regulatory provisions that could result in increased labor requirements or capital investments by industry or government that are not included in the baseline.[14] For the purpose of transparency, we include footnotes presenting the information on data inputs and the details of the calculations for each rule provision for which monetization is feasible.

6.1.1 Wage Rates and Loaded Wage Factors

Many of the calculations in this analysis used wage rates for Arctic OCS oil and gas workers and for BOEM and BSEE employees. For this analysis, we obtained median industry hourly wage rates from the Bureau of Labor Statistics (BLS) May 2014 Occupational Employment Statistics for the industry labor categories. We also obtained median hourly wage rates for BOEM and BSEE personnel from the Office of Personnel Management 2014 General Schedule for the government labor categories. Exhibit 4 presents these hourly wage rates.

[14] The recordkeeping burden costs for this rulemaking are included in these cost estimates and in the Paperwork Reduction Act statement for the rule, which addresses recordkeeping requirements only.

To account for employee benefits, we multiplied the hourly wage rates by appropriate loaded wage factors to generate hourly compensation rates. For industry employees, we used a private-sector loaded wage factor of 1.43 derived from the 2014 BLS index for salary and benefits. For BOEM and BSEE employees, we used a Federal loaded wage factor of 1.69 derived from a U.S. Department of Labor analysis of overhead costs (in the absence of a similar estimate for BOEM or BSEE).[15] We multiplied the hourly wage rates by the appropriate loaded wage factor to estimate the hourly compensation rates.

Exhibit 4. Compensation Rates Used in the Analysis

Industry Occupation	Median Hourly Wage Rate	Estimated Hourly Compensation Rate	Details (Occupation Title, Occupation Code, NAICS/Location)
Senior Engineer	$83.69	$120.03	Architectural and Engineering Managers, 11-9041, 211100
Clerical/Administrative Staff	$20.54	$29.46	Secretaries and Administrative Assistants, 43-6010, 211100
Manager	$69.90	$100.25	General and Operations Managers, 11-1021, 211100
Mid-Level Engineer	$68.20	$97.82	Petroleum Engineers, 17-2171, State of Alaska
Skilled Laborer	$40.00	$57.37	Based on BSEE's knowledge of the industry
Environmental Specialist	$44.88	$64.37	Environmental Scientists and Specialists, 19-2041, 211100
Electrician	$38.28	$54.90	Electrician, 47-2111, State of Alaska
Government Occupation	**Hourly Rate**	**Estimated Hourly Compensation Rate**	**Details (GS Grade and Step, Locality)**
BSEE Mid-level Engineer	$49.02	$82.84	13.5, State of Alaska
BSEE Inspector	$57.92	$97.88	14.5, State of Alaska
BSEE Senior Engineer	$57.92	$97.88	14.5, State of Alaska
BSEE Administrative Staff	$23.24	$39.28	7.5, State of Alaska
BSEE Program Analyst	$41.22	$69.66	12.5, State of Alaska
BSEE Supervisory Engineer	$68.13	$115.14	15.5, State of Alaska
BOEM Regulatory Analyst	$34.39	$58.12	11.5, State of Alaska
BOEM Petroleum Engineer	$41.22	$69.66	12.5, State of Alaska

[15] The 1.69 index is derived by using the BLS index for salary and benefits plus a U.S. Department of Labor analysis of overhead costs averaged over agency employees.

BOEM Geologist	$41.22	$69.66	12.5, State of Alaska
BOEM Chief, Plans Section	$57.92	$97.88	14.5, State of Alaska
BOEM Regional Supervisor	$68.13	$115.14	15.5, State of Alaska

Sources: BLS May 2014 Occupational Employment Statistics; Office of Personnel Management 2014 General Schedule Locality Pay Tables.

6.1.2 Daily Rig Operating Costs and Drilling Season

Some regulatory provisions impact the time available for productive drilling operations. To monetize the impacts of these provisions, we estimated the daily operating costs for affected rigs. Based on industry comments, BOEM and BSEE reevaluated the daily operating costs of rigs on the Arctic OCS. We assume that rigs on the Arctic OCS will fall into two categories: they will be similar to either the Noble *Discoverer* or the Transocean *Polar Pioneer* – two rigs that were contracted to perform drilling operations during 2015.[16] Daily operating cost estimates for these two sample rigs include the cost of the rig operation and the cost of support vessels. Using data from these rigs and associated support vessels, we assume the daily operating cost of a rig and associated support vessels on the Arctic OCS will be $3.97 million in 2014 dollars. For the purposes of the analysis, we assume that the daily rig operating costs remain constant (in 2014 dollars) over the 10-year analysis period.

Another assumption used throughout the analysis is an estimate for the duration of the drilling season. Based on historical ice patterns, we assume that the drilling season on the Arctic OCS begins on July 7 and that seasonal ice encroachment begins on November 1. Given the relief rig drilling requirements, we assume that exploratory drilling or other work below the surface casing must end 34 days before the

[16] While the drilling rigs assumed in this scenario are drillships or semisubmersibles, the Bureaus acknowledge that Arctic wells can potentially be drilled with other types of rigs including drilling barges and jack-ups. In light of the fact that the floating rig day rate cost is generally higher than for bottom-founded rigs, operations using such facilities would likely face lower costs. The Bureaus chose to assume the use of drillships or semisubmersibles as a conservative analytical approach for costing purposes to ensure that costs were not underestimated. Such an assumption is also consistent with recent Arctic exploratory operations.

beginning of seasonal ice. These constraints lead us to assume that the duration of the drilling season is 82 days.[17]

6.1.3 Burden to Review Paperwork Submissions

For each paperwork submission, BOEM and BSEE estimate the labor hours needed by industry to compile and submit its information. To estimate the corresponding burden for BSEE, we generally assume that for every hour that industry devotes to compiling and submitting information, BSEE will need one half hour to review the submission.[18, 19]

6.1.4 Discounting Assumptions

The estimated costs of the rule are presented in two different variations, both in aggregate over the scenario period and as annual averages. The aggregate costs are shown using 3- and 7-percent discount rates. Discounting makes costs occurring in different periods comparable by allowing them to be expressed in present value terms. Costs discounted at a higher rate are worth less in present value terms than costs discounted at a lower rate.

The annual average costs are annualized over the 10 years of exploration activity. The reader should also note that the annual costs to industry vary during the 10-year period of analysis. These changes occur due to a variety of factors including, but not limited to, new rigs entering the sites, different equipment requirements, and other similar factors that occur throughout the analysis period. Although the scenario covers 10 numbered years, only 9 of those years include drilling activity given the necessary plans required in the first year to be able to drill in year 2.

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[17] July 7th through October 31st is 116 days (116 days – 34 days = 82 days). This estimate assumes demobilization is initiated before historical ice encroachment on November 1st and does not differentiate between the Beaufort and Chukchi Sea planning areas.
[18] The submissions to BOEM under part 550 of the rule do not follow this standard review estimate because these submissions will require a more time-intensive review by several employees.
[19] BSEE based the one half-hour estimate on previous paperwork burden statements, which assume that the government burden is half the industry burden (see the paperwork burden supporting statement 1014-0018).

6.2 Scenario Assumptions

The final RIA has changed some of the scenario assumptions from the initial RIA. The final RIA generally retains the 10 years of exploration activity levels consistent with those examined in the initial RIA.

6.2.1 Exploration Scenario

Based on BOEM's and BSEE's knowledge of operators engaged in, or likely to be engaged in, Arctic OCS exploration activities, we made several assumptions about the number of operators, rigs, and wells operating on the Arctic OCS over the 10-year analysis period. We also made assumptions about the number of APDs, EPs, IOPs, and OSRPs that Arctic OCS operators will submit. These assumptions are changed slightly from the proposed rule and corresponding initial RIA. The two primary changes involve the temporal commencement of future exploratory drilling and the presence or absence of an idle relief rig.

The ability to estimate the commencement of future exploration activity is highly uncertain. Since the NPRM was published, Shell, Statoil, and ConocoPhillips have announced that they will suspend or pause exploration activity offshore Alaska and will not be operating on the Arctic OCS for the foreseeable future. These major leaseholders in the Chukchi and Beaufort Sea planning areas have relinquished most or all of their Arctic leases held at the time of the NPRM. This analysis continues to estimate activity for 10 years but does not estimate when future exploration will begin. BOEM and BSEE concluded that a 10-year analysis with numbered years rather than calendar years provides the best overall opportunity to reasonably forecast estimated costs and benefits likely to result from this rule.

The analysis does not extend beyond 10 years since a longer period introduces even greater uncertainty associated with predicting industry's activities and the advancement of technical capabilities. For example, the costs associated with a particular new technology might decrease over time as the technology is adopted more broadly. In other cases, an existing technology might be replaced by a lower-cost alternative as business needs drive technological innovation. Predicting, planning, or projecting costs associated with technological innovation is very difficult due to unknown technological or business constraints that could drive a product into mainstream adoption or into obsolescence. The regulated community also has difficulty in planning for technological innovation far into the future. BOEM and BSEE are not estimating when Arctic exploration will recommence and further extrapolating results will produce results that are more ambiguous and, therefore, be disadvantageous in determining actual costs and benefits likely to result from this rule.

The exploration activity scenario no longer includes an idle relief rig. The proposed rule scenario assumed that operators in years 1 and 2 would decide to meet the relief rig requirement by having a standby, idle rig available. Following the comment review and an analysis of information related to 2015 operations in the Chukchi Sea, BOEM and BSEE conclude that, in future drilling seasons, with clear rulemaking requirements in place, an operator will likely decide to conduct operations with more than one rig and cross-designate those rigs as relief rigs for the other rig, rather than contract for an idle relief rig to meet regulatory requirements. When multiple operators are drilling, each operator will designate another drilling rig as the designated relief rig rather than contract for an idle relief rig to meet regulatory requirements. This assumption was confirmed through comment review. During years when a single operator is drilling (years 2 and 3), we believe an operator will bring two MODUs to the Arctic. While operators may prefer to bring only one rig to the Arctic, the regulatory requirements at §§ 250.470 and 250.472 require at least two since a relief rig must be available to drill a relief well within 45 days of a well control event. Since two rigs are required, it is assumed that operators will choose to productively employ the second rig in active exploration.

However, BOEM and BSEE acknowledge that a company may not choose to bring more than one drilling rig to the Arctic if not for the relief rig requirement in this rule. 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 or most efficient use of its capital. It may prefer to explore elsewhere or deploy its capital on development projects rather than exploration. While it may not be optimal, it is assumed to be the most likely scenario under the regulation. The cost for an idle relief rig is no longer assumed in the analysis; however, we acknowledge that it is not a cost free decision for operators and lessees.

BOEM and BSEE assume 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 2 (with advanced planning work in year 1) and two more operators conducting exploratory drilling beginning in year 4. This is BOEM and BSEE's conservative (i.e., to avoid underestimating expected activity) projection of the number of operators expected to conduct exploratory drilling on the Arctic OCS when it recommences.

We make the following assumptions about submittals to BOEM and BSEE:

(1) We assume that the number of wells drilled and the number of APDs submitted to BSEE will be equal for each year of the analysis period.

(2) We assume that each operator will submit to BOEM an EP in the year prior to exploratory drilling. Since EPs can be submitted several years in advance of drilling, can cover multi-year operations, and may involve multiple well sites, this simplifying assumption is a conservative estimate.

(3) We assume that an IOP and OSRP will be submitted by each operator in each year prior to drilling.

We based all assumptions on our experience with recent and expected industry practices for operators on the Arctic OCS, including information submitted to BOEM and BSEE by lessees and operators and other available information related to planned or potential industry exploratory activities for the analysis period. We summarize these assumptions in Exhibit 5.

Exhibit 5. Assumptions about the Affected Population of Operators and Drilling Operations

Inputs[1, 3]	Yr-1	Yr-2	Yr-3	Yr-4	Yr-5	Yr-6	Yr-7	Yr-8	Yr-9	Yr-10
Operators	0	1	1	3	3	3	3	3	3	3
Primary rigs	0	2	2	4	4	4	4	4	4	4
Standby relief rigs[2]	0	0	0	0	0	0	0	0	0	0
Exploratory wells drilled each year	0	4	4	6	6	6	6	6	6	6
Applications for permit to drill	0	4	4	6	6	6	6	6	6	6
Exploration plans	1	1	3	3	3	3	3	3	3	3
Integrated operations plans	1	1	3	3	3	3	3	3	3	3
Oil spill response plans	1	1	3	3	3	3	3	3	3	3

[1] These estimates are the maximum that BOEM and BSEE assume could be expected in any one year; they should not be viewed as additive. For example, in year 4, up to three operators and up to six wells could be expected.
[2] We refer to relief rigs that are not conducting exploratory drilling as “standby relief rigs.” These rigs would incur different costs than relief rigs conducting exploratory drilling (i.e., “primary rigs” or “operating rigs”). While the exploration scenario in the proposed rule included a standby relief rig, this final rule scenario assumes designated relief rigs will be actively drilling.
[3] BOEM and BSEE do not anticipate that activity under this scenario will begin for at least several years.

6.2.2 SCCE and Resource Sharing

The SCCE resource-sharing assumptions presented in the cost analysis section represent the most likely scenario based on recent Arctic operations and BOEM’s and BSEE’s knowledge of the industry. In the initial RIA, BOEM and BSEE also considered a low-cost scenario and a high-cost scenario that varied the assumptions for resource sharing and SCCE purchases by operators. Some of the comments provided on the proposed rule indicated that companies might not be inclined to engage in resource sharing, however experience in the GOM with SCCE systems demonstrates that sharing can and does occur. BOEM and BSEE do not prevent, and in fact encourage, resource sharing.

Moreover, the rule’s requirements allow for resource sharing and we assume that, to minimize costs, industry will engage in resource sharing whenever possible. We acknowledge that as more operators enter the Arctic, they might not all choose to share the same SCCE. For that reason, we have assumed that two operators will share one set of SCCE, but a third operator will acquire its own SCCE when it begins operations in year 4. That is, we assume two sets of SCCE will be purchased and deployed, with one operator going alone, and two operators engaged in SCCE resource sharing. Again, this is consistent with experience in the GOM where multiple SCCE systems exist, and operators share those systems.

As discussed in 6.2.1, we also assume there will be inter-company relief rig agreements in all years in which there are multiple operators (2021-2026). Therefore, if a relief rig is needed, another actively drilling rig will cease its exploration drilling operations and begin drilling a relief well. This assumption was supported as reasonable in public comments.

6.3 Transfers

We identified no transfer payments associated with the rule. Transfer payments, as defined by OMB Circular A-4, are payments from one group to another that do not affect total resources available to society. Transfer payments are associated with a distributional effect but do not result in additional economic benefits or costs to society.

7. Analysis of Costs and Benefits Assigned to the Rule

The analysis presented in this section describes the potential costs and benefits of the rule compared to the baseline. The following will result in a change from the baseline:

(a) Additional Incident Reporting Requirements;

(b) Additional Pollution Prevention Requirements;

(e) Additional Information Requirements for APDs;

(f) Incorporation of API RP 2N, Third Edition;[20]

(g) SCCE Requirements;

(h) Additional Relief Rig Requirements;

(i) Additional Auditing Requirements;

[20] API RP 2N, Third Edition, "Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions" is incorporated by reference in § 250.198 of this rulemaking.

(j) Real-time Location Tracking Requirements;

(k) IOP Requirements;

(l) Planning Information Requirements to Accompany EPs; and

(m) Industry Familiarization with the New Rule.

7.1 Costs of the Rule's Provisions

This section analyzes the costs of the rule's provisions that represent costs above the baseline. These requirements and their associated costs to industry and government are presented in the sections below. This Final RIA closely mirrors the language of the rule; however, the rule's regulatory text reflects what will become legally binding.

Exhibit 6 presents a summary of the costs to industry and to BSEE/BOEM of the Final Rule by provision. The exhibit provides information on the labor category required for each cost component, whether the labor category corresponds to industry or BSEE/BOEM, the number of labor hours the cost component will require, the labor cost per hour, and the total labor costs to industry and BSEE/BOEM. These cost components are then discussed below in further detail.

Exhibit 6. Labor Cost Components of the Rule

	Type of Labor Required		Labor Hours Per (Year)		Labor Costs Per Hour		Total Labor Costs	
Provision	**Industry**	**BSEE / BOEM**	**Industry**	**BSEE / BOEM**	**Industry**	**BSEE / BOEM**	**Industry**	**BSEE / BOEM**
250.188(c) per rig	Mid-level Engineer	Senior Engineer	100	50	$97.82	$97.88	$9,782	$4,894
	Professional Engineer		50	0	$120.03	$0.00	$6,002	
250.300(b) (1),(2) per rig	Rig Crew – Tool Pusher		*	0	$57.37	$0.00	*	$0
	Professional Engineer		*	0	$120.03	$0.00		
250.470(a)-(d) per rig	Senior Manager		12	0	$120.03	$0.00	$1,440	$0

Provision	Type of Labor Required		Labor Hours Per (Year)		Labor Costs Per Hour		Total Labor Costs	
	Industry	BSEE / BOEM	Industry	BSEE / BOEM	Industry	BSEE / BOEM	Industry	BSEE / BOEM
	Manager	Senior Engineer	20	16	$100.25	$97.88	$2,005	$1,566
250.470(a)-(d) per well	Manager	Senior Engineer	14	7	$100.25	$97.88	$1,404	$685
250.470(g) per rig	Mid-level Engineer	Senior Engineer	20	10	$97.82	$97.88	$1,956	$979
250.471(b) per rig	Rig Crew		30	0	$165,277	$0.00	$4,997,990	$0
250.471(b) per well	Rig Crew		24	0	$165,277	$0.00	$3,966,659	$0
250.471(c) per well	Mid-level Engineer	Mid-level Engineer	10	5	$97.82	$82.84	$978	$414
250.471(e), (f) per well	Admin. Staff Person	Inspector	40	20	$29.46	$97.88	$1,178	$1,958
250.470(f) per APD	Mid-level Engineer	Mid-level Engineer	60	30	$97.82	$82.84	$5,869	$2,485
250.1920 (b),(c),(f)		Admin. Staff Person	0	44	$0.00	$39.28	$0	$1,724
		Mid-level Engineer	0	351	$0.00	$82.84	$0	$29,093
		Supervisory Engineer	0	44	$0.00	$115.14	$0	$5,055
254.80(c)	Env. Scientist	Mid-level Engineer	6	3	$64.37	$82.84	$386	$249
550.204	Mid-level Engineer	Regulatory Analyst	2880	120	$97.82	$58.12	$281,722	$6,974
		Petroleum Engineer	0	120	$0.00	$69.66	$0	$8,359
		Geologist	0	160	$0.00	$69.66	$0	$11,146
		Chief	0	160	$0.00	$97.88	$0	$15,661
		Regional Supervisor	0	160	$0.00	$115.14	$0	$18,422
550.220(a), (b),(c)	Mid-level Engineer	Regulatory Analyst	1050	24	$97.82	$58.12	$102,711	$1,395
		Petroleum Engineer	0	24	$0.00	$69.66	$0	$1,672
		Geologist	0	32	$0.00	$69.66	$0	$2,229
		Chief	0	32	$0.00	$97.88	$0	$3,132

Provision	Type of Labor Required		Labor Hours Per (Year)		Labor Costs Per Hour		Total Labor Costs	
	Industry	BSEE / BOEM	Industry	BSEE / BOEM	Industry	BSEE / BOEM	Industry	BSEE / BOEM
		Regional Supervisor	0	32	$0.00	$115.14	$0	$3,684
Industry Familiarization	Professional Engineer		151	0	$120.03	$0.00	$18,155	$0

*Labor costs are included in the total cost estimate provided in industry comments. No specific labor hours designations are available.

7.1.1 (a) Additional Incident Reporting Requirements (§ 250.188)

Section 250.188(c) includes incident-reporting requirements for operators on the Arctic OCS beyond those already required. Operators will be required to provide an immediate oral report to the BSEE onsite inspector, if one is present, or otherwise to the Regional Supervisor of any sea ice movement or condition having the potential to affect operations or trigger ice management activities. Operators also will be required to report the start and termination of such activities, as well as any "kicks" or unexpected operational issues that could result in the loss of well control. Operators also will be required to submit a follow-up written report regarding any ice management activities undertaken, within 24 hours following completion of those activities. These requirements will help ensure that BSEE is notified in sufficient time to oversee the safety of an operator's reactions and to prepare in the event that a response will be necessary due to a safety or environmental incident resulting from an ice event.

Although some incident reporting is required under current regulations, this rule adds new reporting and timing requirements. We calculated the annual labor cost per rig by multiplying the time required for each report by the median hourly compensation rates for the labor categories of individuals most likely to complete these activities. The result was an annual labor cost to industry per rig of $15,784.[21] To

[21] We assume that incidents having new reporting requirements under the rule will occur two times a year for each rig. We assume that industry mid-level engineers will spend 50 hours and industry senior engineers will spend 25 hours on reporting requirements. We multiplied the time spent on reporting by the median hourly compensation rate for senior engineers for an annual cost per rig associated with incident reporting of $15,784.

estimate the cost to BSEE to review these reports, BOEM and BSEE multiplied the total hours assumed to review these reports by the hourly compensation rates for the labor categories of individuals most likely to complete these activities. The result was an annual labor cost to BSEE per rig of $4,894.[22] Exhibit 7 summarizes the annual costs for the incident reporting requirements.

Exhibit 7. Additional Incident Reporting Requirements (§ 250.188)

Year	Number of Rigs	Industry Cost per Rig	Industry Annual Cost	Agency Cost per Rig	Agency Annual Cost
	A	B	C = A × B	D	E = A × D
1	0	$15,784	$0	$4,894	$0
2-3	2	$15,784	$31,567	$4,894	$9,788
4-10	4	$15,784	$63,134	$4,894	$19,576

7.1.2 (b) Additional Pollution Prevention Requirements (§ 250.300)

Sections 250.300(b)(1) and 250.300(b)(2) include revised pollution prevention requirements for exploratory drilling operations on the Arctic OCS. Operators will be required to capture all petroleum-based mud and cuttings from operations that use petroleum-based mud. In addition, these subparagraphs clarify the Regional Supervisor's discretionary authority to require operators to capture all water-based muds and associated cuttings from Arctic OCS exploratory drilling operations. This capture may be required after completion of the hole for the conductor casing to prevent the discharge of water-based mud and associated cuttings into the marine environment, based on factors including, but not limited to:

(1) The proximity of the exploratory drilling operations to Alaska Native subsistence activities;

(2) The extent to which discharged mud or cuttings might cause marine mammals to alter their migratory patterns in a manner that interferes with subsistence activities; or

[22] Using assumptions similar to those for industry, we assume that BSEE will review the oral and written reports as submitted (i.e., twice per year). We assume that a BSEE senior engineer will spend 25 hours reviewing each submittal. We multiplied the time spent on review by the compensation rate to estimate a $4,894 per rig cost to review.

(3) The extent to which discharged mud or cuttings might adversely affect marine mammals, fish, or their habitat.

Addressing both environmental concerns and the concerns of Alaska Natives regarding the potential impacts of discharges of mud and cuttings, these pollution prevention requirements will help prevent or minimize the likelihood of environmental damage and interference with Alaska Natives' subsistence activities from discharges of mud and cuttings.

BOEM and BSEE consider the requirement to capture all petroleum-based mud and cuttings to be in the baseline, as this is prohibited by EPA through the National Pollutant Discharge Elimination System. It was also previously required by BOEM and BSEE as a condition for EP approval. BOEM and BSEE consider the costs associated with the Regional Supervisor's exercise of his discretion to require the collection of water-based muds and cuttings a cost attributable to this rule.

To provide a cost estimate of the Regional Supervisor's discretion, we consider the circumstances under which this discretion may be used. Given the requirements of the rule, such discretion may be exercised when concerns arise regarding marine mammals, subsistence activities, etc. Therefore, we find that this discretion most likely will be exercised with regard to operations in the Beaufort Sea. This finding is consistent with the approval of the 2012 exploration program in the Beaufort Sea, which included a private agreement between the company and the Alaska Eskimo Whaling Commission to collect water-based mud and cuttings. Costs for this provision are estimated based on an annual per-rig cost. We assume that one of the four rigs that ultimately drill in the Arctic OCS will drill in the Beaufort Sea. However, to avoid underestimating the cost of this provision, BOEM and BSEE assume that one rig drilling in every year of the scenario will be required to capture water-based muds and cuttings.

Based on cost estimates received in comments, we assume that the cost to add capture equipment to a drilling rig will be $13 million, which is incurred in year 2 when the first rig begins drilling in the Arctic. Further, the annual operation of this equipment and disposal of cuttings is estimated to cost an additional

$16.5 million. We assume the capital costs will be incurred in year 2 and annual operating expenses will be incurred in years 2 to 10.

Exhibit 8. Additional Pollution Prevention Requirements (§ 250.300) ($ millions)

Year	Number of Rigs	Capital Cost per Rig	Operating Cost per Rig	Annual Cost
	A	B	C	D = A × (B + C)
1	0	$0	$0	$0
2	1	$13.0	$16.5	$29.5
3-10	1	$0	$16.5	$16.5

7.1.3 (e) Additional Information Requirements for APDs (§ 250.470)

Section 250.470 requires operators to submit Arctic OCS-specific information with APDs for Arctic OCS exploratory drilling. Paragraph (a) requires operators to submit a detailed description of how the drilling unit, equipment, and materials will be prepared for service in Arctic OCS conditions and in compliance with the requirements of section 250.417.[23] Under paragraph (b), operators are required to submit a detailed description of all operations necessary in Arctic OCS conditions to transition the rig from being under way to commencing drilling operations and from concluding drilling operations to being under way, as well as any anticipated repair and maintenance plans for the drilling unit and equipment. Paragraph (c) requires operators to submit well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well. Under paragraph (d), operators are required to submit information on weather and ice forecasting capability for all phases of drilling operations. The informational requirements in the new section are necessary to inform BSEE’s evaluation of APDs for Arctic OCS exploratory drilling operations.

The requirements under sections 250.470(a)–(d) result in labor costs to industry and BSEE. Based on additional information we received in comments, BOEM and BSEE increased their estimates of the

[23] A definition of “Arctic OCS conditions” is provided in §§ 250.105 and 550.105 of the rule.

industry and BSEE staff time needed with regard to this section. Consolidating and reporting information will result in an annual labor cost to industry of $3,445 per rig and $1,404 per well.[24] The cost of review by BSEE results in an annual labor cost of $1,566 per rig and $685 per well.[25] Exhibit 9 and Exhibit 10 summarize the annual costs associated with these information requirements.

Exhibit 9. Information Requirements under §§ 250.470(a) and (d) for Applications for Permit to Drill by Rig

Year	Number of Rigs	Industry Cost per Rig	Industry Annual Cost	Agency Cost per Rig	Agency Annual Cost
	A	B	C = A × B	D	E = A × D
1	0	$3,445	$0	$1,566	$0
2-3	2	$3,445	$6,891	$1,566	$3,132
4-10	4	$3,445	$13,781	$1,566	$6,264

Exhibit 10. Information Requirements under §§ 250.470(b) and (c) for Applications for Permit to Drill by Well

Year	Number of Wells	Industry Cost per Well	Industry Annual Cost	Agency Cost per Well	Agency Annual Cost
	A	B	C = A × B	D	E = A × D
1	0	$1,404	$0	$685	$0
2-3	4	$1,404	$5,614	$685	$2,741
4-10	6	$1,404	$8,421	$685	$4,111

7.1.4 (f) Incorporation of API RP 2N, Third Edition (§ 250.470)

Section 250.470(g) requires operators to submit a detailed description of how the relevant aspects of API RP 2N, Third Edition, "Planning, Designing, and Constructing Structures and Pipelines for Arctic

[24] We assume that costs associated with consolidating and reporting information as required under §§ 250.470(a) and (d) will be incurred per rig, while costs associated with §§ 250.470(b)–(c) will be incurred per well. We assume that consolidating and reporting the information required under §§ 250.470(a) and (d) will require 20 hours and 12 hours of managerial time per rig, respectively. We assume that consolidating and reporting the information required under §§ 250.470(b) and (c) will require 14 hours per well. We multiplied the number of hours by the median hourly compensation rate for an industry manager to obtain an annual labor cost to industry of $3,445 per rig and $1,404 per well.

[25] We assume that for every hour industry spends to report and consolidate the information, BSEE spends one half hour to review the information. We assume that 16 hours per rig and 7 hours per well will be required for a BSEE senior engineer to review the information. We multiplied the number of hours by the hourly compensation rate for a BSEE senior engineer to obtain an annual labor cost to BSEE of $1,566 per rig and $685 per well.

Conditions" are addressed in planning exploratory drilling operations. The document also will be included in the list of documents incorporated by reference in section 250.198 of the rule. API RP 2N, Third Edition, is a voluntary consensus standard that addresses the unique Arctic conditions that affect the planning, design, and construction of systems used in Arctic and sub-Arctic environments.

This requirement results in labor costs to industry and BSEE. Documentation will result in an annual labor cost to industry per rig of $1,956. Review of submittals results in an annual labor cost per rig of $979 to BSEE.[26] Exhibit 11 summarizes the annual costs associated with this requirement.

Exhibit 11. Annual Information Requirements for Applications for Permit to Drill Related to API RP 2N (§ 250.470(g))

	Number of Rigs	Industry Cost per Rig	Industry Annual Cost	Agency Cost per Rig	Agency Annual Cost
Year	A	B	C = A × B	D	E = A × D
1	0	$1,956	$0	$979	$0
2-3	2	$1,956	$3,913	$979	$1,958
4-10	4	$1,956	$7,826	$979	$3,915

7.1.5 (g) SCCE Requirements (§ 250.471)

Section 250.471 describes SCCE requirements for exploration wells drilled on the Arctic OCS. For operations using a MODU when drilling or working below the surface casing, paragraph (a) requires operators to have access to a capping stack, a cap-and-flow system, and a containment dome, positioned to ensure that the SCCE will arrive within specified periods after a loss of well control. This equipment also must be able to be deployed as directed by the Regional Supervisor pursuant to paragraph 250.471(g) of the rule. Paragraph (a)(2) requires that the cap and flow system be designed to capture at least the

[26] We assume that a mid-level engineer will spend 20 hours on the documentation associated with this requirement. We multiplied the number of hours by the median hourly compensation rate for mid-level engineers to obtain a labor cost to industry of $1,956 per rig. We assume that a senior BSEE engineer will spend 10 hours reviewing submittals associated with this requirement. We multiplied the number of hours by the hourly compensation rate to obtain a cost to BSEE per rig of $979.

amount of hydrocarbons equivalent to the calculated worst-case discharge rate referenced in the BOEM-approved EP. Paragraph (a)(3) requires the containment dome to have the capacity to pump fluids without relying on buoyancy. The SCCE capital cost, deployment and testing of this equipment is a compliance cost of the rule.

7.1.5.1 SCCE Equipment Requirements

The rule requires operators to have access to, and the ability to deploy promptly, SCCE when drilling or working below the surface casing. This requirement largely specifies for Arctic exploratory drilling the existing SCCE regulatory requirements clarified in NTL No. 2010-10, dated November 8, 2010, when drilling with subsea BOPs or surface BOPs on floating facilities. While the requirement to have available Arctic SCCE is currently reflected in NTL 2010-10, it is still a compliance cost attributable to this rule given unique Arctic SCCE equipment/design requirements and SCCE deployment timeframes not specifically required in existing BSEE regulations. Additionally, NTL s could be subject to future clarifications/interpretations when the need arises or circumstances change.

The equipment requirements under section 250.471(a) will result in capital costs to industry. We assume that one-time capital costs for operators that purchase this equipment will be $270 million per SCCE purchased. As discussed in Section 6.2.2, BOEM and BSEE assume that some operators would engage in resource sharing of SCCE due to the high costs of this equipment.

We assume that, over the course of the 10-year analysis period, two operators would share one set of SCCE, but the third operator would purchase its own equipment. We assume no additional costs to the entity that engages in resource sharing. To estimate the SCCE capital and labor costs to industry, we accounted for the number of purchased sets of SCCE and the number of deployed sets of SCCE on the Arctic OCS. Exhibit 12 summarizes the annual capital costs of the SCCE requirements under section 250.471(a).

Exhibit 12. Source Control and Containment Equipment Requirements (Capital Costs – § 250.471) ($ millions)

Year	Number of SCCE Purchased	One-time Purchase Cost per SCCE	Total Capital SCCE Costs
	A	B	C = A × B
1	0	$270.0	$0
2	1	$270.0	$270.0
3	0	$270.0	$0.0
4	1	$270.0	$270.0
5-10	0	$270.0	$0.0

Because the industry currently does not engage in resource sharing on the Arctic OCS, BOEM and BSEE have no details as to how such arrangements will be executed. The SCCE resource sharing assumptions presented here and explained in Section 6.2.2 represent the most likely scenario based on current experience with similar equipment in the GOM and based on BOEM and BSEE's expectations of the industry.

7.1.5.2 Stump Testing Requirements

Paragraph 250.471 (b) requires operators to conduct a monthly stump test of dry-stored capping stacks and, if using a pre-positioned capping stack (PPCS), a stump test must be conducted prior to each installation on each well. Paragraph (c) requires operators that propose to change their well design to include in their Application for Permit to Modify (as required by existing section 250.465(a)) a reevaluation of their SCCE capabilities and a demonstration that their SCCE capabilities will meet the criteria in section 250.470(f) under the changed well design. Paragraph (d) requires the operator to conduct tests or exercises of the SCCE when directed by the Regional Supervisor. Paragraph (e) requires the operator to maintain records pertaining to testing, inspection, and maintenance of the SCCE for 10 years, and to make them available to BSEE upon request. 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 to make them available to BSEE upon request.

These requirements reflect the need for operators conducting exploratory drilling on the Arctic OCS to be able to correct or contain any loss of well control as quickly as possible to minimize the impacts of oil pollution on the environment. The requirements also address the need for Arctic OCS operators to plan for response redundancies and operational complexities. Such planning is needed in the face of potential challenges regarding the logistics and transit times to respond to an Arctic OCS well control event. Related challenges involve difficulties associated with oil spill response operations in Arctic OCS conditions and limited ability on the Arctic OCS to summon additional source control and containment resources.

Additionally, section 250.470(f) requires operators who propose to use a MODU to conduct exploratory drilling operations below the surface casing on the Arctic OCS to provide with their APD information concerning their required SCCE capabilities, including a statement that the operator owns, or has a contract with a provider for, SCCE capable of controlling or containing the identified worst-case discharge.[27] Specifically, operators will be required to include a detailed description of SCCE capabilities; inventory of local and regional SCCE, supplies, and services owned by the operator (or for which the operator has a contract with a provider); and, where necessary, proof of contracts or membership agreements for SCCE or related supplies and services. Operators also are required to include a detailed description of procedures for SCCE inspection, testing, and maintenance. In addition, operators are required to provide a detailed description of plans to ensure that personnel are trained to deploy and operate the equipment. They are also required to provide plans for maintaining ongoing proficiency in source control operations. These APD documentation requirements for SCCE help assure BSEE that operators conducting exploratory drilling can properly address any loss of well control under Arctic OCS conditions.

[27] Calculation of the volume of oil associated with a worst-case-discharge scenario varies from site to site. This information is required as part of the oil spill response plan for each facility under 30 CFR 254.47.

We estimate the cost to industry per stump test for dry-stored capping stacks to be $1,665,997. Tests for dry-stored capping stacks are conducted monthly during the three months of the active drilling season for a total annual cost per rig of $4,997,990.[28] We estimate a cost of $1,983,330 per stump test for a PPCS and a cost of $1,983,330 for the installation for a PPCS.[29] Exhibit 13 summarizes the stump test cost for the SCCE requirements.

Exhibit 13. Stump Tests within the Source Control and Containment Equipment Requirements (§ 250.471(b))

Year	Number of Available Dry-Stored Capping Stacks	Annual Testing Cost per Dry-Stored Capping Stack	Number of Wells with PPCSs	Testing Cost per Well with a PPCS	Installation of a PPCS per well	Annual Cost
	A	B	C	E	D	F = (A × B) + (C × D) + (C × E)
1	0	$4,997,990	0	$1,983,330	$1,983,330	$0
2-3	1	$4,997,990	0	$1,983,330	$1,983,330	$4,997,990
4-10	2	$4,997,990	1	$1,983,330	$1,983,330	$13,962,640

7.1.5.3 Well Design Change Information Requirements

[28] We assume that it will take the entire rig crew 10 hours to complete each stump test for a dry-stored capping stack. We multiplied the portion of a rig-day (10 hours / 24 hours) by the daily rig operating cost for the Arctic OCS to obtain a cost per stump test for a dry-stored capping stack of $1,665,997. We assume that each rig with a dry-stored capping stack will conduct three monthly tests (once each in July, August, and September - the active drilling season) for a total annual cost per rig of $4,997,990. We assume that both rigs drilling in years 2 and 3 share one dry-stored capping stack. In years 4-10 we assume that a second operator will bring an additional dry-stored capping stack for the third rig. This is consistent with the resource sharing assumptions made for the SCCE capital costs.

[29] A PPCS may be utilized below subsea BOPs when deemed technically and operationally appropriate, such as when using a jack-up rig with surface trees. The PPCS must be tested prior to installation on each well. For the test, we assume the entire rig crew will spend 12 hours on the stump tests for a PPCS. We calculated the costs to industry by multiplying the portion of day spent on the test (12 hours / 24 hours) by the daily operating cost for a rig on the Arctic OCS. These costs resulted in a cost to industry per stump test for a PPCS of $1,983,330. To account for the installation cost of the PPCS, we assume that the entire rig crew will spend an additional 12 hours installing the PPCS. We calculated the costs to industry by multiplying the portion of the day spent on installation (12 hours / 24 hours) by the daily rig operating cost on the Arctic OCS. This results in a cost to industry for PPCS installation of $1,983,330. We assume that no wells will be drilled using a PPCS in years 2 and 3 and that one operator will use a PPCS to drill one well annually in years 4-10.

We assume that the requirement to submit a reevaluation of SCCE in the event of any changes to well design will result in labor costs to both the industry and BSEE. Documentation results in an average labor cost to industry per well of $978. We calculated a per-well labor cost for BSEE of $414.[30] Exhibit 14 summarizes the annual costs associated with this requirement.

Exhibit 14. Information Requirements Associated with Well Design Changes (§ 250.471(c))

Year	Number of Wells	Industry Cost per Well per Year	Annual Cost to Industry	Agency Cost per Well Per Year	Annual Cost to Agency
	A	B	C = A × B	D	E = A × D
1	0	$978	$0	$414	$0
2-3	4	$978	$3,913	$414	$1,657
4-10	6	$978	$5,869	$414	$2,485

7.1.5.4 Test and Exercise Requirements

We assume that the tests initiated by the Regional Supervisor as described in paragraph (d) will be conducted annually for each SCCE in use. We used costs received in comments based on 2015 operations and assume this annual exercise cost is $5.9 million. We assume this cost will be required for all SCCE in operation in a given year.[31] Exhibit 15 summarizes the Regional Supervisor-initiated test and exercise costs within the SCCE requirements.

[30] We assume that a mid-level engineer will spend 10 hours on the documentation associated with this requirement. We multiplied the number of hours by the median hourly compensation rate for mid-level engineers to obtain a labor cost to industry of $978 per well. We assume that a mid-level BSEE engineer will spend 5 hours on the review of submittals associated with this requirement, or one half hour for every hour the industry spends to consolidate the information. We multiplied the number of hours by the hourly compensation rate to obtain a cost to BSEE per well of $414.

[31] We assume that Regional Supervisor-initiated tests and exercises for SCCE will be conducted annually and that labor and equipment costs associated with these activities will be $5.9 million per SCCE.

Exhibit 15. Regional Supervisor-initiated Tests and Exercises within the Source Control and Containment Equipment Requirements (§ 250.471(d)) ($ millions)

Year	Number of SCCEs	Cost per SCCE	Annual Cost
	A	B	C = A × B
1	0	$5.9	$0
2-3	1	$5.9	$5.9
4-10	2	$5.9	$11.8

Records Maintenance Requirements

SCCE records maintenance requirements result in annual labor costs to industry and to BSEE. SCCE records maintenance requirements result in a cost to industry per well of $1,178. Labor associated with these records maintenance requirements result in an annual labor cost to BSEE per well of $1,958.[32] Exhibit 16 summarizes the records maintenance requirements within the SCCE requirements for both the industry and BSEE.

Exhibit 16. Records Maintenance Requirements within the Source Control and Containment Equipment Requirements (§ 250.471(e))

Year	Number of Wells	Industry Cost per Well	Annual Industry Cost	Agency Cost per Well	Annual Agency Cost
	A	B	C = A × B	D	E = A × D
1	0	$1,178	$0	$1,958	$0
2-3	4	$1,178	$4,714	$1,958	$7,830
4-10	6	$1,178	$7,070	$1,958	$11,746

[32] We assume that administrative staff will spend 40 hours per well on this required SCCE records maintenance. We multiplied the number of hours by the median hourly compensation rate for administrative staff to obtain an annual labor cost per well associated with these records maintenance requirements of $1,178. We also assume that a BSEE inspector will spend 20 hours per well to review these records, assuming that agency review takes one half hour for every hour of industry burden. We multiplied the number of hours by the hourly compensation rate for a BSEE inspector to obtain an annual labor cost per well of $1,958.

7.1.5.5 Documentation Requirements

We calculated the labor costs to industry associated with SCCE documentation to be $5,869 per APD. A labor cost of $2,485 per APD was calculated for BSEE.[33] Exhibit 17 summarizes the APD document requirements regarding SCCE for both the industry and the government. Based on industry input, BOEM and BSEE increased the number of hours assumed for both industry and BSEE to comply with SCCE documentation.

Exhibit 17. APD Documentation Requirements for Source Control and Containment Equipment (§ 250.470(f))

	Number of APDs	Industry Cost per APD	Annual Industry Cost	Agency Cost per APD	Annual Agency Cost
Year	A	B	C = A × B	D	F = A × D
1	0	$5,869	$0	$2,485	$0
2-3	4	$5,869	$23,477	$2,485	$9,941
4-1	6	$5,869	$35,215	$2,485	$14,911

7.1.6 (h) Additional Relief Rig Requirements (§ 250.472)

Section 250.472 describes the relief rig requirements for the Arctic OCS. Operators on the Arctic OCS, when conducting exploratory drilling or working below the surface casing, will be required to have a relief rig, distinct from their 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. The requirement to maintain the capacity for completing a relief well prior to seasonal ice encroachment will effectively limit the number of days an operator can drill or work below the surface casing at the end of each drilling

[33] We assume that industry mid-level engineers will spend 60 hours on these SCCE documentation requirements. We multiplied the number of hours by the median hourly compensation rate for mid-level engineers to obtain a labor cost of $5,869 per APD. We also assume that a mid-level BSEE engineer will spend 30 hours to review these submittals. We multiplied the number of hours by the hourly compensation rate for mid-level engineers to obtain a labor cost to BSEE of $2,485 per APD.

season. This limitation on certain operations could result in some costs to operators from forgone activity, even though some operations that do not involve work below the surface casing can be done at the well site at the end of the season. The relief rig also must comply with all other requirements of Part 250 for drilling operations and be able to drill a relief well under anticipated Arctic OCS conditions. Paragraph (a) also authorizes the Regional Supervisor to direct an operator, in the event of a loss of well control, to drill a relief well using the relief rig described in the operator's APD.

Section 250.470(e) requires operators submitting APDs for exploratory drilling on the Arctic OCS to submit a detailed description with the APD of how they will comply with the requirements under section 250.472. Both the relief rig requirements and the SCCE requirements (discussed above) are 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 capital costs of the relief rig provisions are discussed in Section 7.1.6.1, and the costs for the drilling season limitations (the "shoulder season") are discussed in Section 7.1.6.2.

7.1.6.1 Relief Rig Requirements: Capital Costs

A relief rig is required (see § 550.213) by DOI in approving EPs in all OCS areas. This regulatory requirement was clarified in NTL No. 2010-N06, dated June 18, 2010. The initial RIA included the cost of a relief rig in the rule's compliance cost estimate. BOEM and BSEE's revised activity assumptions no longer assume that companies will assign an idle relief rig and instead assume they will have two rigs actively drilling and each would mutually serve as the other's relief rig.

BOEM and BSEE assume that all operators conducting exploratory drilling in year 2 and thereafter will designate another operating rig as a relief rig. This would be accomplished through inter-company agreements or a company designating its second operating rig as a relief rig. As a result, no standby relief rigs are assumed and no cost is associated with the capital requirement of a relief rig. As discussed in Section 6, a company may not have chosen to bring more than one drilling rig to the Arctic if not for the relief rig requirement in this rule. 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 if its capital resources.

7.1.6.2 Relief Rig Requirements: Shoulder Season

The second part of this regulatory provision requires the cessation of exploratory drilling or working below the surface casing far enough in advance of the expected return of seasonal ice to allow for completion and abandonment of a relief well. The rule establishes a 45-day maximum limit on the time necessary to complete relief well operations under § 250.472. The length of the "shoulder season" (up to 45 days) is a period of time operators may not drill or work below the surface casing. The actual shoulder season length depends on the amount of time an operator can demonstrate it will take for its relief rig to arrive on site, drill a relief well, kill and abandon the original well and abandon the relief well.

BOEM and BSEE-approved plans for the 2012 and 2015 Arctic operations required drilling operations to be concluded 38 and 34 days, depending on relief rig location, before November 1, respectively. These deadlines were chosen based on satellite imagery showing historical data on the earliest encroachment of sea ice over the applicant's drill site (November 1) and the estimated time required for a relief rig to mobilize to the correct location and complete relief well operations. BOEM and BSEE's assessment of the drilling plan and the length of the shoulder season is dependent on where the relief rig is stationed and its operational readiness to deploy and conduct relief well operations. Based on BOEM and BSEE's previous EP and permit conditions, BOEM and BSEE have demonstrated that the rule's 45-day requirement is a maximum and that full amount of time may not be required, based on the typical location of an Arctic relief rig and ability to transport and drill in a reduced period. For the purpose of assigning compliance costs of this requirement, we assume that the shoulder season will be 34-days, rather than the maximum of 45-days, since that was the amount of time in the 2015 approved plan.

The initial RIA assumed that the 38 day shoulder season in the 2012 approved plan was included in the regulatory baseline and assumed only the difference (7 days) between the 2012 approved plan of 38 days and the maximum 45-day duration as part of the compliance cost. However, upon further review of comments, BOEM and BSEE determined that the shoulder season requirement should be considered as a compliance cost of the rule, but for the purposes of the RIA, this requirement is assumed to be 34 days since that was the amount of time in the 2015 approved plan. Any additional time (up to the 45-day maximum) would be the product of operator choice and decisions regarding staging and capabilities, not the rule (i.e., BOEM and BSEE certainly are not requiring operators to take longer than necessary to perform relief well operations). Further, it is unlikely that operators will use the full 45 days rather than a reduced duration given the time necessary to position and drill a relief well.

To calculate the impact of this "shoulder season," BOEM and BSEE considered the portion of a full drilling season during which a rig would be unable to operate. Absent this requirement, the drilling season is approximately 116 days (from July 7 through October 31). Assuming the relief rig is available in the same area as the well, operations below the surface casing would need to end 34 days before the end of the drilling season. This effectively shortens the drilling season by 29 percent (34 / 116 days). We assume that 29 percent of the annual cost of the drilling rig is lost because of this provision.[34] We also assume, however, that a savings is realized for the support vessels. Given that the operation ends 34 days earlier, the support vessels are assumed to begin the demobilization sooner, resulting in cost savings. The cost savings does not increase proportionally based on the number of rigs operating given the presence of

[34] We assume the annual cost of the drilling rig for the purpose of the shoulder season is the annual cost to contract a drilling rig. We assume a day rate of approximately $510,000 for a total annual cost of a drilling rig of approximately $186 million. The cost of the shoulder season would then be approximately $53.97 million per rig. The estimated cost of the shoulder season does not consider the longer timeframes required for companies to undertake their Arctic OCS exploration programs.

shared support vessels. BOEM and BSEE note that companies can still undertake some productive activities on their leases during the shoulder season. However, to avoid underestimating costs, we have not made adjustments for time spent on these other operations. Therefore, the costs for the shoulder season in Exhibit 18 present a likely over-estimate of the true cost of the shoulder season provision.

Exhibit 18. Shoulder Season Costs ($ millions)

Year	Number of Rigs	Cost of Idle Drilling Time (per rig, per season)	Savings in Vessel Time (total, per season)	Shoulder Season Cost
	A	B	C	D = (A × B) - C
1	0	$53.97	$0	$0
2-3	2	$53.97	$23.5	$84.4
4-10	4	$53.97	$37.9	$178.0

7.1.7 (i) Additional Auditing Requirements (§ 250.1920)

Section 250.1920 increases the audit frequency and facility coverage for Arctic OCS exploratory drilling operations. Operators are generally required to conduct their Safety and Environmental Management Systems (SEMS) audit every 3 years after their initial audit. BSEE concludes, however, that performing a SEMS audit of Arctic OCS exploratory drilling operations and all related infrastructure each year in which drilling is conducted is critical because of the particularly challenging conditions and high-risk nature of those activities.

We accounted for the costs associated with the increased audit frequency by assuming that the incremental burden of additional audits will be incurred every year. [35] We calculated the cost of these audits by multiplying the total cost per audit for a high-activity operator by the number of operators. We

[35] We assume that the audit costs occur in each year and the audit will focus on the SEMS requirements for Arctic operations rather than a company's general SEMS implementation and compliance. This assumption is conservative; however, this does not imply that audits will necessarily happen in this sequence.

assume that the audit cost per operator to industry will be $250,000, based on industry input.[36] We assumed that the audit cost per operator to BSEE will be $35,872.[37] Exhibit 19 summarizes these costs.

Exhibit 19. Additional Auditing Requirements (§ 250.1920)

	Number of Audits	Industry Cost per Audit	Industry Annual Cost	Agency Cost per Audit	Agency Annual Cost
Year	A	B	C = A × B	D	E = A × D
1	0	$250,000	$0	$35,872	$0
2	1	$250,000	$250,000	$35,872	$35,872
3	1	$250,000	$250,000	$35,872	$35,872
4	3	$250,000	$750,000	$35,872	$107,617
5	3	$250,000	$750,000	$35,872	$107,617
6	3	$250,000	$750,000	$35,872	$107,617
7	3	$250,000	$750,000	$35,872	$107,617
8	3	$250,000	$750,000	$35,872	$107,617
9	3	$250,000	$750,000	$35,872	$107,617
10	3	$250,000	$750,000	$35,872	$107,617

7.1.8 (j) Real-time Location Tracking Requirements (§ 254.80)

Section 254.80 describes additional information requirements for the emergency response action plan section of the oil spill response plan (OSRP) for operators conducting exploratory drilling on the Arctic OCS. Only section 254.80(c) imposes a new burden on industry and BSEE. Paragraph (c) requires operators to describe how they maintain an effective tracking and management system that can locate in real time all response equipment and personnel conducting response activities, or transiting to and from

[36] In this rulemaking, this cost estimate originates from 30 CFR Part 250, Subpart S – Safety and Environmental Management Systems (SEMS), OMB Control Number 1014-0017. Based on industry input, the annual per-operator cost for an audit was doubled.

[37] In 30 CFR Part 250, Subpart S – Safety and Environmental Management Systems (SEMS), OMB Control Number 1014-0017, BSEE estimates that the burden for BSEE to review audits is 28,527 hours, with 10 percent of the hours for clerical support, 80 percent of the hours for a mid-level engineer, and 10 percent of the hours for a supervisory engineer. Based on industry input and because this regulation covers audits for 130 operators, we estimate that one audit will take 440 hours. To estimate the cost, we assume that a clerk will spend 44 hours, a mid-level engineer will spend 351 hours, and a supervisory engineer will spend 44 hours. To estimate the per-audit cost to BSEE, we multiplied the corresponding hourly compensation rates by the allocated hours to estimate a $35,872 per-audit cost.

the response site(s). This system is essential to provide the Unified Command with information necessary to ensure that sufficient personnel and equipment will be available to meet the response needs. These information requirements result in a labor cost to industry of $386 per OSRP and a labor cost to BSEE of $249 per OSRP.[38]

In addition to the reporting costs, BOEM and BSEE estimated the cost for complying with section 254.80(c) by using an automatic identification system (AIS) to track both equipment and personnel during the drilling season. Operators have the flexibility to choose a system to monitor their equipment and personnel during the drilling season; however, we use the AIS as a representative system for these cost estimates. BOEM and BSEE estimated the per-entity cost to have AIS devices on vessels and tracking devices on equipment and personnel based on the costs incurred by the initial operator. We recognize that this cost will vary based on implementation for each operator. However, we do not have the additional information needed to determine the specific costs of each expected operator, and that cost will vary by the size of the operation (e.g., vessels, equipment, and personnel). Using information on the current tracking systems, we estimated the cost per system, including the purchase of tracking devices, the purchases of AIS devices, the installation of the tracking devices and AIS units, the monthly fee for tracking devices, and the annual fee for AIS services. Exhibit 20 presents the unit costs, the number of units, and the total cost for the AIS system.[39] We considered all costs to be upfront costs, except for the monthly fee for tracking devices and the annual fee for the AIS. BOEM and BSEE assume that operators will need to replace the AIS (including the main unit and tracking devices) every 8 years.

[38] We assume that industry environmental specialists will spend 6 hours to include the required information in the response plan. We multiplied the number of hours by the median hourly compensation rate for environmental specialists to obtain a labor cost to industry per OSRP of $386. We also assume that a BSEE mid-level engineer will spend 3 hours on these information requirements or one half hour for every hour of industry burden. We multiplied the number of hours by the hourly compensation rates for mid-level engineers to obtain a labor cost to BSEE of $249 per OSRP. BOEM and BSEE assume that each operator will submit one OSRP in the year prior to drilling.

[39] We assume that an electrician will need to install the AIS unit onto vessels and that installation will take 12 hours per device. We multiplied the hours spent by the electrician to install the device by the median hourly compensation rate for electricians to obtain a cost per device installation of $659. We assume that a crew member will install the tracking devices on the equipment and that it will take one half hour per tracking device. We multiplied that time by the median hourly compensation rate for a rig crew member to estimate an installation cost of $29 per device.

Exhibit 20: Automatic Identification System Costs per Entity (§ 254.80(c))

AIS Cost Inputs per Entity	Unit Cost	Number of Units	Total Cost
Purchase tracking/locator devices – personnel	$150	100	$15,000
Purchase tracking/locator devices – equipment	$100	187	$18,700
Purchase AIS (small vessels)	$1,000	6	$6,000
Purchase AIS (larger vessels)	$3,000	4	$12,000
Tracking device installation (rig crew installer)	$29	187	$5,364
AIS installation (electrician)	$659	10	$6,588
Monthly fee for tracking/locator devices – personnel*	$10	100	$5,000
Monthly fee for tracking/locator devices – equipment	$10	187	$9,350
AIS annual fee (per user name)	$1,000	25	$25,000
Upfront Cost**			**$63,652**
Annual Cost			**$39,350**

*We assume that the monthly tracking fees for both personnel and equipment occur during the 5-months of drilling, mobilization, and demobilization.

**We assume that operators pay the upfront cost at the start of every lifecycle, or every 8 years.

We estimate the total annual recurring cost of AIS by multiplying the estimated average cost per operator by the number of operators. As was shown in Exhibit 5, we assume new operators in years 2 and 4. We also estimate the upfront cost to replace the AIS device and tracking units in year 8 for the original operator based on the 8-year lifecycle cost of AIS.[40] We estimate the recurring cost of AIS by multiplying the recurring cost by the number of operators each year. Exhibit 21 presents details on the AIS costs.

[40] We assume that training costs for AIS are already accounted for under SEMS requirements.

Exhibit 21. Real-time Location Tracking Requirements (§ 254.80(c))

	Number of New AIS	Upfront Industry Cost per Operator	Annual Cost	Number of Active AIS	Annual Industry Cost per Operator	Annual Cost
Year(s)	A	B	C = A × B	D	E	F = D × E
1	0	$63,652	$0	0	$39,350	$0
2	1	$63,652	$63,652	1	$39,350	$39,350
3	0	$63,652	$0	1	$39,350	$39,350
4	2	$63,652	$127,304	3	$39,350	$118,050
5-10	0	$63,652	$0	3	$39,350	$118,050

7.1.9 (k) IOP Requirements (§ 550.204)

Section 550.204 requires operators proposing to conduct exploratory drilling operations on the Arctic OCS to develop an IOP for each proposed exploratory drilling program, and to submit the IOP to DOI, acting through its designee, BOEM, at least 90 days in advance of filing its EP. The IOP will need to describe how the proposed exploratory drilling program will be designed and conducted in an integrated manner that accounts for Arctic OCS conditions and address each information requirement identified in section 550.204. In the IOP, operators will be required to include information on several aspects of operations:

- Vessels and equipment (including general maintenance schedule),
- Schedule and objectives of the exploratory drilling program (including contractor work on critical components, plans for abandonment, and timelines for each objective),
- Mobilization and demobilization operations (including tow plans suitable for Arctic OCS conditions),
- Weather and ice forecasting capability,
- Work to be performed by contractors,
- Operational safety,
- Preparations and plans for staging of oil spill response assets,
- Efforts to minimize impacts of exploratory drilling operations on local community infrastructure, and

- The extent to which the project will rely on local community workforce and spill cleanup response capacity.

We assume an operator normally gathers this information to develop its approach for conducting exploratory operations, and operators will merely provide existing information under the umbrella of the IOP. The IOP process is intended to facilitate the sharing of information among the relevant Federal agencies and the State of Alaska and to provide the public an early view of the operator's plans and improve the execution of exploratory operations and safety. The IOP process also provides relevant agencies an early opportunity to engage in a meaningful and constructive dialog with operators with the ultimate goal of crafting a fully complete and detailed EP.

These information requirements result in labor costs to industry and BOEM. Labor costs to industry were estimated to be $281,721 per IOP, which reflects an adjustment from prior estimates based on new information that was received in comments. We calculated the labor costs to BOEM to be $60,562 per IOP.[41]

7.1.10 (l) Planning Information Requirements to Accompany EPs (§ 550.220)

Section 550.220 includes additional information requirements for planning information that must accompany EPs for operators proposing to conduct exploration activities on the Arctic OCS. Paragraph (a) requires operators to have emergency plans to respond to a fire, explosion, personnel evacuation, or loss of well control, and a loss or disablement of a drilling unit, vessel, offshore vehicle, or aircraft. Paragraph (c) requires operators proposing exploration activities on the Arctic OCS to submit additional

[41] We assume that mid-level engineers will spend 2,880 hours to compile and include the required information in the IOP. BSEE and BOEM revised this assumption from the proposed rule based on comments received. We multiplied the number of hours by the median hourly compensation rate for mid-level engineers to obtain a cost to industry of $281,721 per IOP. We also assume that several BOEM employees will review these documents, including a regulatory analyst (120 hours), a petroleum engineer (120 hours), a geologist (160 hours), a BOEM Chief (160 hours) and a Regional Supervisor (160 hours). We multiplied the number of hours by the hourly compensation rate for each respective labor category to obtain a cost to BOEM of $60,562 per IOP. BOEM and BSEE assume that one IOP is submitted per operator each year in the year prior to drilling.

planning information to accompany EPs, including 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. These information requirements will help ensure, through advanced planning, the safety of operations in the challenging Arctic OCS conditions.

These information requirements result in labor costs to industry and BOEM of $102,711 and $12,112 per EP, respectively.[42] We then accounted for the number of EPs expected to be submitted each year for operations on the Arctic OCS to obtain a total labor cost to industry of $2,362,353 and to BOEM of $278,587.

7.1.11 (m) Industry Familiarization with the New Rule

When the new regulation takes effect, industry will need to read and interpret the rule. Through this review, operators will familiarize themselves with the structure of the new rule and identify any new provisions relevant to their operations. Operators will also evaluate whether any new action must be taken to achieve compliance with the rule. Additionally, after the first year an annual cost will be incurred for operators to reacquaint themselves with the rule.

Reviewing the new regulations will require staff time, imposing an initial one-time and a recurring labor cost on industry. We estimated the labor cost for industry familiarization with the rule to be $378,095.[43] BSEE and BOEM revised the estimated cost of familiarization with the rule based on comments received.

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[42] We assume that mid-level engineers will spend 1,050 hours to compile and include the required information for the EP. This assumption was revised from the proposed rule based on industry comments. We multiplied the number of hours by the median hourly compensation rate for mid-level engineers to obtain a cost to industry of $102,711 per EP. We also assume that several BOEM employees will review these documents including a regulatory analyst (24 hours), a petroleum engineer (24 hours), a geologist (32 hours), a BOEM Chief (32 hours), and a Regional Supervisor (32 hours). We multiplied the number of hours by the hourly compensation rate for each respective labor category to obtain a cost to BOEM of $12,112 per EP. BOEM and BSEE assume that each operator will submit an EP in the year prior to drilling.

[43] We assume that, for each operator on the Arctic OCS, a senior engineer will spend 250 hours to review the new regulation. In addition, we assume that each operator will spend an additional 120 hours a year reviewing these regulations to prepare for the drilling season. BSEE and BOEM reevaluated this assumption for the final rule based

7.1.12 Summary of the Rule's Quantitative Costs

Exhibits 22 and 23 summarize the cost analysis. Exhibit 22 summarizes the 10-year average annual costs (undiscounted) for the rule by provision. Exhibit 23 summarizes the costs to industry and the government using discount rates of 3 percent and 7 percent. Similar to the analyses presented above, the summation of the individual cost items in Exhibit 22 and Exhibit 23 might not equal the total shown, due to rounding.

Exhibit 22. 10-Year Average Annual Costs by Provision (with no discounting)

Provision	10-year Average Annual Costs ($ millions)
(a) Additional Incident Reporting Requirements	$0.07
(b) Additional Pollution Prevention Requirements	$16.15
(e) Additional Information Requirements for APDs	$0.03
(f) Incorporation of API RP 2N, Third Edition	$0.01
(g) Additional SCCE Requirements	$74.28
(h) Relief Rig Requirements	$141.45
(i) Additional Auditing Requirements	$0.66
(j) Real-time Location Tracking Requirements	$0.11
(k) IOP Requirements	$0.89
(l) Planning Information Requirements to Accompany EP	$0.30
(m) Industry Familiarization with the New Rule	$0.04
TOTAL	$233.98

Exhibit 23. Summary of Monetized Costs

Year	Industry Costs ($ millions)	Government Costs ($ millions)	Total Costs ($ millions)
	A	**B**	**C = A + B**
1	$0.47	$0.07	$0.55
2	$395.65	$0.15	$395.79
3	$113.35	$0.29	$113.65
4	$492.54	$0.39	$492.93
5	$222.42	$0.39	$222.81

on industry comment. We multiplied the number of hours by the median hourly compensation rate for a senior engineer to obtain a cost to industry of $378,095.

6	$222.42	$0.39	$222.81
7	$222.42	$0.39	$222.81
8	$222.42	$0.39	$222.81
9	$222.42	$0.39	$222.81
10	$222.42	$0.39	$222.81
Undiscounted 10-year total	$2,336.52	$3.24	$2,339.76
Present value 10-year total with 3% discounting	$2,044.82	$2.78	$2,047.60
Present value 10-year total with 7% discounting	$1,736.72	$2.30	$1,739.01
Average Annual (Years 1-10)	$233.65	$0.32	$233.98

7.2 Benefits of the Rule's Provisions

As discussed, this rule includes ten new provisions which add costs above the baseline. These provisions, their costs, and primary benefits are presented in Exhibit 24. The benefits of these incremental costs are varied and each will be discussed in turn.

Exhibit 24: Rule Provisions

Provision	11 Year Rule Costs (3% discounted $ millions)	Percent of New Rule Costs	Primary Benefit
(a) Additional Incident Reporting Requirements	$0.56	0.03%	Improves information to Federal agencies
(b) Additional Pollution Prevention Requirements	$141.09	6.89%	Minimizing natural resource impacts
(e) Additional Information Requirements for APDs	$0.23	0.01%	Improves information to Federal agencies
(f) Incorporation of API RP 2N	$0.08	0.00%	Reducing risk of a spill
(g) Additional SCCE Requirements	$681.92	33.30%	Improving spill control and containment
(h) Relief Rig Requirements	$1,206.55	58.93%	Improving spill control and containment
(i) Additional Auditing Requirements	$5.58	0.27%	Improves information to Federal agencies
(j) Real-time Location Tracking Requirements	$0.96	0.05%	Improves information to Federal agencies
(k) IOP Requirements	$7.67	0.37%	Improving coordination among Federal agencies

(l) Planning Information Requirements to Accompany EPs	$2.57	0.13%	Improves information to Federal agencies
(m) Industry Familiarization with the New Rule	$0.37	0.02%	General
Total	$2,047.60	100.00%	

In addition to the benefits outlined in the next four sections, BOEM and BSEE also acknowledge that this rule may have additional benefits in preventing and/or mitigating the impacts or severity of smaller, non-catastrophic oil spills. Many of the provisions of this regulation require companies to conduct significant advanced planning to adequately prepare for the severe Arctic environment, both operationally and for purposes of spill response. Such planning may lead to a reduction in mishaps and small mistakes which could lead to a non-catastrophic oil spill and enhance operators' ability to respond effectively to a spill. Similarly, the utility of much of the equipment required by the rule for Arctic exploratory drilling operations is not limited to addressing catastrophic spills but can improve operator response capabilities for losses of well control and non-catastrophic oil spills, as well. These benefits are not quantified but instead acknowledged here qualitatively.

7.2.1 Benefit: Improving Information and Coordination among Federal Agencies

The regulation includes new provisions that require additional information sharing and availability. The additional requirements for incident reporting, APDs, auditing, and real-time location tracking improve information sharing to Federal agencies. In addition, the IOP requirements increase the information to and improve the coordination among the federal regulatory community. This coordination within the federal family enables agencies to better identify risk mitigations early in the planning process. Because the nature of this benefit is difficult to quantify, it is considered qualitatively. The cost of the applicable provisions totals $17.6 million and comprises 1 percent of the compliance cost assigned to the rule. These provisions are designed to provide more information to BSEE and BOEM about an operator's experiences in the region and to improve the coordination among BSEE, BOEM, and other Federal agencies. For example, the information required in section 550.204 facilitates 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*.[44] Compiling this information might also ultimately lead to improved planning on the part of the operator. 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 informed coordination and information sharing between Federal agencies is documented in Executive Order 13580, which created the Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska.[45] This Executive Order 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 fostering communication and collaboration with government partners. The enhanced planning driven by the new rules will also advance safety and environmental protection by promoting earlier and more thorough operational planning to identify and address vulnerabilities well in advance of operations.

7.2.2 Benefit: Minimizing Natural Resource and Subsistence Impacts

The additional pollution prevention requirements in section 250.300(b)(1) and section 250.300(b)(2) 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. If exercised,

[44] http://www.doi.gov/news/pressreleases/upload/Shell-report-3-8-13-Final.pdf
[45] https://www.whitehouse.gov/the-press-office/2011/07/12/executive-order-13580-interagency-working-group-coordination-domestic-en.

the authority in this provision will protect natural resources and minimize the impact of Arctic OCS exploratory activities on marine mammals, their habitat, and subsistence activities. Given the difficulty of calculating how the localized 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 precautions, where implemented, are necessary to preserve a food source and cultural tradition. For comparison, BOEM estimates that the combined value of subsistence harvests in the Chukchi and Beaufort Seas are more than $114 million per year.[46]

7.2.3 Benefit: Reducing the Risk of Catastrophic Oil Spill

BSEE and BOEM attribute the incorporation of API RP 2N into this rule as reducing the risk of a catastrophic oil spill. 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. Section 7.2.3.1 provides BOEM and BSEE's best estimate of the frequency/probability of a catastrophic oil spill resulting from loss of well control. Estimating the probability that an oil spill will occur is very difficult in part because the number of such large incidents offshore is small. Even more difficult is determining the reduction in the 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.

[46] The estimate for annual subsistence harvests is from Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053). Estimated annual subsistence harvests in the Beaufort total approximately $6 million and annual harvests in the Chukchi total approximately $108 million for an aggregate value of $114 million per year.

7.2.3.1 Catastrophic Oil Spill Risk

As described above, a catastrophic oil spill is a "low-probability, high-consequence" event that is not expected to occur yet might cause very large and costly impacts if it did. While unexpected, a catastrophic oil spill could occur as a result of exploratory activity in the Arctic and, if one were to occur, the economic and environmental impacts could be devastating. A catastrophic 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 simplicity of the wells.

A quantitative approach for estimating the relative unlikelihood of low-probability catastrophic oil spills was calculated for the Five-Year OCS Oil and Gas Leasing Program analyses.[47] BOEM applied extreme value statistics to historical OCS spill data to quantify the potential frequency of a catastrophic oil spill for different size spills. Exhibit 25 shows the estimated frequency that one or more catastrophic spills would occur when 50 wells (as in this Arctic RIA scenario) are drilled.

Exhibit 25: Catastrophic Oil Spill Risk and Risked Spill Costs

Spill Size Volume (barrels)	Frequency over Scenario (50 wells)
150,000	0.00282
500,000	0.00211
1,000,000	0.00179
2,000,000	0.00151
5,000,000	0.00121

Clearly a catastrophic oil spill is an unlikely event. However, in managing these types of events, the focus cannot be on the likelihood of failure, but rather must be focused on the high consequences of that

[47] The derivation of this frequency analysis is included in the Draft Economic Analysis Methodology for the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program in Chapter 2. This document is available at: http://www.boem.gov/Economic-Analysis-Methodology/ . Additional information is included in the Outer Continental Shelf Oil and Gas Leasing Program: 2017-2022 Draft Programmatic Environmental Impact Statement. This document is available at: http://boemoceaninfo.com/u/dpeis/dpeis_volume_I.pdf

failure. As demonstrated by the *Deepwater Horizon* oil spill, even these low probability events can occur, and when they do they have devastating economic and environmental consequences.[48] Accordingly, BOEM and BSEE included provisions in these regulations designed to minimize the consequences of the unlikely event. Section 7.2.4 discusses the provisions associated with reducing the severity of a catastrophic oil spill and estimates the potential costs which could result from a catastrophic oil spill.

7.2.4 Benefit: Reducing the Duration of a Catastrophic Oil Spill

Though a catastrophic oil spill is an unlikely event, prudent management of the consequences of such an event provides for safeguards to reduce the duration and severity of a spill should one occur. The SCCE and relief rig provisions of this rule are designed to reduce the duration and severity of a catastrophic oil spill from a well control event. These provisions make up 92 percent of the rule's compliance costs.

The SCCE provisions of the rule involve capital, testing, and documentation requirements. The capital requirement for operators to have access to SCCE is designed to stop or capture the flow of hydrocarbons after a loss of well control event has occurred. This provision requires a capping stack, cap-and-flow system, and containment dome all be positioned nearby to control or contain hydrocarbons from a well control event.

This rule requires operators to have access to a capping stack capable of being deployed to the well site within 24 hours of a loss of well control, which would be a first response to prevent the uncontrolled discharge of fluids. The second component of SCCE is the cap and flow system, which must be on site within 7 days of a loss of well control event. This system must be capable of handling discharge volumes up to the worst case discharge estimates identified in exploration plans. If this system is unsuccessful, a

[48] By its own account, BP has spent more than $14 billion to date in cleanup operations related to the Deepwater Horizon spill. In addition to cleanup costs, BP has agreed to pay $20.8 billion to Federal, State, and local governments and close $20 billion to private parties for natural resources damages, economic claims, and other expenses. As explained in this RIA, the costs and other consequences of a major spill in the waters of the Arctic OCS likely would be greater than the costs and impacts for a comparable spill in the Gulf of Mexico, where response equipment and resources are more readily available than in the Arctic region. Economic damages, on the other hand, may be lower due to the remoteness of the Arctic OCS from tourist and commercial activities.

third layer of redundancy is also required to be available within 7 days of a loss of well control event, the containment dome. Together, these systems provide layers of redundancy which would be in place quickly to stop or contain the flow of hydrocarbons within days of a loss of well control. This would prevent or reduce damage while a relief well is drilled to permanently plug and abandon the uncontrolled well.

In addition to the capital requirement for the availability of SCCE, the testing requirements can help reduce the duration or severity 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 more efficient and effective 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.

The rule also requires operators to have a relief rig available nearby and capable of drilling a relief well before the end of open water season. The SCCE provides an interim solution to minimize harm, while the relief rig requirement is designed to be a permanent solution to stop the flow of hydrocarbons from a loss of well control event. The regulation requires the capability to drill a relief well within 45 days of the loss of well control event. An operator need not, and should make efforts to not, utilize this entire length of time, which could be reduced if the relief rig is stationed closer to the site of the well. The requirement to have a relief rig available and capable of drilling a relief well before the end of the open water season ensures that any catastrophic oil spill could be controlled before seasonal ice encroachment.

The scale of benefits from the SCCE and relief rig provisions is determined by their effectiveness in stopping or containing a spill already underway and in reducing the overall risk of a catastrophic oil spill. Due to the uncertainties in estimating changes in the overall probability of different catastrophic oil spill sizes, BOEM and BSEE focus on the consequences of such spills and how these provisions can help mitigate those consequences. Section 7.2.4.1 provides information on the costs of a catastrophic oil spill which recognizes the range of consequences in the unlikely event of a catastrophic oil spill. This section also includes a discussion of the non-monetized costs associated with a catastrophic oil spill. These discussions are designed to supplement the discussion in the text regarding the baseline benefits of the rule.[49] Although this discussion focuses on catastrophic oil spills, benefits could also be realized with smaller non-catastrophic oil spills if contained more quickly.

7.2.4.1 Catastrophic Oil Spill Costs

To estimate the potential consequences of a catastrophic oil spill, we used data from a BOEM analysis prepared for the 2017-2022 Five-Year OCS Oil and Gas Leasing Program.[50] We also used estimates from Shell's 2012 and 2015 Arctic EPs. The data from these documents are supplemented with additional information from other sources.

For this analysis, we estimate the social cost of an oil spill, that is, the private costs plus external effects. The private costs are represented by the lost value of hydrocarbons plus the sum of containment and clean-up costs. The external effects are represented by the cost to society from ecological damages, injuries, fatalities, and subsistence losses.

We separately estimated oil spill costs that would scale proportionally with the size of the spill (per-barrel costs) and those that would be fixed, regardless of the spill size (fixed or per incident costs). Together, these cost estimates represent the social cost of a spilled barrel of oil, consistent with the directive of OMB Circular A-4, which is to include costs regardless of where, when, or to whom the costs accrue.[51]

[49] Consistent with guidance provided by OMB Circular A-4, when the non-quantified benefits are important, the RIA should indicate which non-quantified effects are most important and why.

[50] The catastrophic oil spill analysis is included in the Draft Economic Analysis Methodology for the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program in Chapter 2. This document is available at: http://www.boem.gov/Economic-Analysis-Methodology/ . Additional background data for the information provided in the Draft Economic Analysis Methodology can be found in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).

[51] Using both natural resource damages and containment and cleanup costs is consistent with the natural resource damages assessment methods described in the Draft Economic Analysis Methodology for the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program. This approach accounts for any temporal or spatial distribution in the accrual of cleanup costs. For example, the cleanup on the coastal area might occur later and in a different place than the initial spill.

Some of our estimates of costs are represented by a range over which the actual results are anticipated to occur in the event of a catastrophic oil spill. As mentioned previously, however, the effects of a catastrophic spill can vary widely for many reasons (e.g., the type and amount of oil, location of the spill, areal distribution of the release, sensitivity of the affected ecosystem, and weather), so it is conceivable that the actual costs could lie outside the ranges provided. Also, while our analysis includes important private and external costs of a catastrophic oil spill, some subsets of these costs are not included in this analysis because they are not priced in the market and, thus, are difficult to monetize. One such example is the cost associated with damaged ecosystem services. Accordingly, the true costs to society of a spill (i.e., the benefits to society of avoiding a spill) could be larger than identified here if other non-market measures of lost value were quantifiable in dollar terms. Section 7.2.4.1.1 outlines some of the additional non-monetized costs which would add to the total damages associated with a catastrophic oil spill. Further, as noted previously, the rule could likewise yield a benefit in reducing the likelihood and potential impact of smaller spills.

The BOEM 2017-2022 Five-Year Program analysis uses data collected from revealed preference studies elsewhere in the nation to estimate avoided costs specific to the Arctic OCS because no incidents have occurred on the Arctic OCS. Given that cost data do not exist for the impact of a catastrophic oil spill in the Arctic, we use available values of the effects of catastrophic oil spills in a nearby region (the Exxon Valdez oil spill) and in other regions (the Gulf of Mexico). These cases provide a next-best estimate of the social cost of a potential catastrophic oil spill by transferring known values to the Arctic OCS. The method is consistent with OMB Circular A-4 as a next-best alternative when collecting primary data is not possible because of resource constraints.

To demonstrate, we first estimate the per-barrel costs of a catastrophic oil spill. Following the same methodology used in the BOEM analysis on the costs of hypothetical catastrophic oil spills, we divided the per-barrel costs into three components: value of lost hydrocarbons, ecological damages, and containment and cleanup costs. The value of the lost hydrocarbons reflects the lost usable oil. We used a

$50 value of lost hydrocarbons per barrel, which is consistent with the average oil price for 2017 estimated by the Energy Information Administration in the May Short-Term Energy Outlook.[52] Naturally, this value could change as market fluctuations change the price of oil.

To estimate ecological damages and containment and cleanup costs, BOEM's Five-Year Program analysis considers the cost of a barrel of oil spilled from historical GOM spills and the Exxon Valdez oil spill in Alaska's Prince William Sound. As noted above, many site-specific characteristics influence the severity of the impacts from an oil spill. The Exxon Valdez oil spill occurred in a highly sensitive region close to populated areas that support economic activity, including recreation, tourism, and commercial fishing. The environmental qualities of the Chukchi and Beaufort Seas are similar (although not identical), but this northern area of Alaska is very different and does not support the same level of economic activity as the Gulf of Alaska where the Exxon Valdez oil spill occurred. For example, no significant commercial fishing occurs in the Arctic, and the region supports relatively little tourism or recreation. The Exxon Valdez spill occurred close to shore, while drilling in the Chukchi Sea is expected to be 50 miles or more from shore. Given the differences in the Arctic and Gulf of Alaska, the Exxon Valdez spill information provides an upper-bound estimate on the per-barrel costs of a spill occurring in the Arctic seas offshore Alaska. To form the lower-bound value of the per-barrel spill estimates, we used the estimates from historical spills in the GOM. The GOM differs significantly from the Arctic in climate, environment, and economic activity. Because the GOM already supports a variety of rigs and oil operations, the region has ready access to labor and capital in the event of an incident, thus minimizing the overall cost of an incident. If a spill occurs on the Arctic OCS, resources and labor would need to be deployed to the region, which would add to the cost and duration of cleanup. Other factors, such as climate for weathering of oil, presence of sea ice and other challenging Arctic conditions would also tend to raise the relative cost for spill response in the Arctic. Thus, estimates from the GOM form a lower-bound estimate on the per-barrel costs of a spill.

[52] http://www.eia.gov/forecasts/steo/.

Ecological damages relate to the Arctic OCS natural resources that would be damaged by an oil spill. To estimate ecological damages, we used values from natural resource damage assessments from historical GOM oil spills and the Exxon Valdez oil spill. We then scaled these costs using Arctic-specific factors from BOEM's Offshore Environmental Cost Model. This approach resulted in a range of ecological damages costs from $2,500 to $9,700 per barrel.[53]

Spill containment and cleanup costs include all the resources (capital and labor) needed to contain the spill and clean up the site. To estimate the cleanup and resource costs, the BOEM Five-Year Program analysis used a range of catastrophic spill cleanup costs from the Exxon Valdez and Deepwater Horizon oil spills. Following the logic outlined above, the cleanup cost estimates from the Deepwater Horizon spill provided the low end of the range, and those from the Exxon Valdez formed the upper limit. Using these limits, we estimate that cleanup and containment cost in the Chukchi and Beaufort Seas are between $5,100 and $16,000 per barrel.[54]

In addition to the per-barrel cost, BOEM also estimated fixed or per-incident costs for fatal and non-fatal injuries on the Arctic OCS and subsistence losses. For the cost of fatal and non-fatal injuries, we again follow the BOEM Five-Year Program analysis, which uses the U.S. EPA's meta-analysis of the value of a statistical life literature to estimate the cost of a fatality to be $9.5 million and the cost of an injury from Viscusi (2005) to be $57,100.[55] We assumed an average of 8 fatalities and 10 non-fatal injuries per incident.[56] This results in a total cost of $76.4 million for catastrophic oil spills in any region. As with all

[53] Derivation of this estimate can be found in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).
[54] Information on the derivation of this estimate is included in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).
[55] Viscusi, W.K (2005), "The Value of Life. Discussion Paper No. 517". Harvard Law School.
[56] To derive the estimate of fatal and non-fatal injuries, BOEM averaged the results of two historical well blowout events that led to fatalities as described in the Draft Economic Analysis Methodology for the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program. The first occurred in 1984 and caused four fatalities and three non-fatal injuries. The second, the *Deepwater Horizon* oil spill, resulted in 11 fatalities and 17 injuries. These results average to 8 fatalities and 10 non-fatal injuries per incident. Additional information on the derivation of this

estimates described in this section, this estimate is based on a hypothetical oil spill and historical data points and the actual cost of a spill could differ widely.

To calculate the per-spill impacts to subsistence harvests, we considered the annual whale harvests and a value per kilogram harvested. Following the methodology adopted in the Five-Year Program analysis, we assumed that harvests would be lost in the year of a catastrophic oil spill and in both the spring and fall harvests of the following year. We assume the harvests in both the Beaufort and Chukchi Sea Planning Areas would be lost regardless of where the oil spill occurred because of the transportation of the oil and migration of the animals, resulting in actual and perceived impact on resources across the Arctic.[57] Using data from the *Final Environmental Impact Statement for Issuing Annual Quotas to the Alaska Eskimo Whaling Commission for a Subsistence Hunt on Bowhead Whales for the Years 2013 through 2018* from NOAA's National Marine Fisheries Service and an assumed value of $120 per kilogram, we estimate the loss of subsistence activities at $209 million.[58] BOEM estimated these costs on a per-incident basis because these costs do not depend on the volume of oil spilled. BOEM notes that these quantifiable subsistence damages capture only a fraction of the cultural damages for Alaska Natives in this region. These losses relate to the monetary value of the harvest but fail to capture the cultural value of the practices for Alaska Natives. The cultural value likely exceeds the market value associated with the subsistence harvest.

Exhibit 26 summarizes the cost of a catastrophic oil spill on the Arctic OCS.

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estimate can be found in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).

[57] Additional information on the derivation of this estimate can be found in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).

[58] Calculation on the loss of subsistence activities is explained in more detail in Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf Oil and Gas Development Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015-053).

Exhibit 26. Cost of a Catastrophic Oil Spill on the Arctic OCS

Cost per Barrel of Oil Spilled	
Value of lost hydrocarbons	$50
Ecological damages	$2,500 – $9,700
Cleanup and containment cost	$5,100 – $16,000
Total Cost per Barrel of Oil Spilled	**$7,650 – 25,750**
One-time Cost per Spill	
Lives lost and non-fatal injuries	$76,400,000
Total estimated subsistence losses	$209,100,000
One-time Cost per Spill in the Chukchi Sea	**$285,500,000**

Exhibit 26 provides an estimate of the impacts of a catastrophic oil spill, but there are numerous other unquantified costs of a catastrophic oil spill. These costs, including damage to the unique Arctic ecosystem, damage to natural resources, and damage to Alaska Native cultural traditions, are not included in the estimates in Exhibit 23 but are discussed qualitatively in Section 7.2.4.1.1.

Although the costs of a catastrophic oil spill can vary based on many factors, given the large per-barrel costs of spilled oil, the total cost of a catastrophic oil spill clearly would greatly depend on the total volume of resources spilled. Using the Shell OSRP's worst-case discharge estimates, we can estimate the daily marginal oil spill cost. To estimate the daily cost of a spill at each location, we multiplied the barrels of oil spilled per day (as estimated in the Shell OSRP and presented in Exhibit 27) by the cost per barrel of oil spilled (as shown in Exhibit 26). Exhibit 27 summarizes this calculation for both the Chukchi and Beaufort Seas. We recognize that the worst-case discharge volumes likely would decline throughout the duration of a loss-of-well-control oil spill and that these estimates in Exhibit 27 represent a maximum amount. We estimated the daily quantifiable cost of a worst-case discharge oil spill to be between $191 million and $644 million for the Chukchi Sea and $122 million and $412 million for the Beaufort Sea.

Exhibit 27. Cost of Oil Spilled per Day

Location	Worst-Case Discharge - Barrels of Oil per Day	Cost per Barrel of Oil Spilled	Cost of Spill per Day ($ millions)
Chukchi Sea	25,000	$7,650 - $25,750	$191 - $644
Beaufort Sea	16,000	$7,650 - $25,750	$122 - $412

Exhibit 28 provides the estimated spill costs for a range of five different spill sizes. The second column of Exhibit 28 provides an estimate of the number of days of an oil spill which could generate the potential costs given in the third and fourth columns. The spill costs given in Exhibit 28 are conditional costs, meaning they are conditional on a spill occurring. Again, because a catastrophic oil spill is a low probability-high consequence event, the conditional spill costs provide the meaningful way to view the impacts. Discounting these spill costs by the low probability distorts the magnitude of the impacts which could result from these activities. Exhibit 28 shows the cost of a catastrophic spill using the cost estimates shown in Exhibit 27 at various different levels of possible spill volumes. The consequence of an oil spill depends on several factors, including the type and amount of oil, the location of the spill, the areal distribution of the release, the sensitivity of the ecosystem affected, and the weather. Accordingly, the cost estimates reflect a wide range of possible spill sizes and impacts.

Exhibit 28. Potential Avoided Oil Spill Costs

Spill Size (barrels)	Estimated Duration (days)*	Potential Avoided Costs ($ million)**
150,000	6 - 9	$1,433 - $4,148
500,000	20 - 31	$4,111 - $13,161
1,000,000	40 - 63	$7,936 - $26,036
2,000,000	80 - 125	$15,586 - $51,786
5,000,000	200 - 313	$38,536 - $129,036

*The estimated duration is calculated based on the daily discharge volumes shown in Exhibit 27. Worst-case discharge volumes are not expected for the duration of any spill as reservoir pressure decreases, flow lessens, and SCCE is deployed.

**The potential avoided costs are derived by multiplying the range of per barrel spill costs shown in Exhibit 26 by the range of spill sizes and adding the per incident costs shown in Exhibit 26.

The costs of the rule are estimated to total $2.3 billion over the 10 years of the analysis period. If these 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 cost.

As discussed in the Need for Regulation, the unique Arctic characteristics increase the possibility that a loss of well control event could become a catastrophic oil spill. The remote location and inability of MODUs to drill during the ice season are factors which could allow an oil spill from a well control event to become catastrophic. Without the provisions in this rule to reduce the duration of a catastrophic oil spill from a loss of well control event, operators may be unable to control the uncontrolled flow of hydrocarbons until the next open water season. Further, regardless of the open water season, the remote location of the Alaskan Arctic limits the availability of support equipment to stop an oil spill in a timely manner. In particular, the requirement for access to SCCE equipment and the requirement that operators be capable of drilling a same season relief well ensure that any loss of well control event can be contained in a reasonable time and within the same open-water season.

The SCCE requirements prevent the loss of precious time in transporting individual pieces of equipment from other regions (e.g., the Gulf of Mexico) in the event of a catastrophic oil spill. As shown in Exhibit 26, the cost of an Arctic oil spill ranges from $7.65 to $25.75 million per day which are potential avoided costs as a result of this regulation. The capping stack is required to be onsite within 24 hours following a loss of well control event, and testing exercises show it could be deployed and effective within 6 hours. The capping stack provides a backup mechanism to regain control over an out of control well if the BOP fails to shut-in an uncontrolled flow from a well. Similarly, the cap and flow system and containment dome systems are required to be onsite within 7 days. We estimate the cap and flow system could be deployed within 28 hours and the containment dome within 48 hours. The requirement that the SCCE be pre-staged in the region can greatly reduce the duration of an oil spill from a well control event and provide large benefits through avoided costs.

The same season relief rig requirement ensures the only 100 percent certain method to stop an uncontrolled flow of hydrocarbons is available and can be completed before the arrival of winter Arctic ice. This final measure in stopping a loss of well control event is estimated to control a well within 34 days. Requiring a designated relief rig avoids days of oil spill damages while another rig is transported to the region. It would take approximately 4 weeks for a rig to travel from the GOM to the Alaskan Arctic or approximately 2.5 weeks for a rig to be relocated from Asia. During this time, substantial damage could be caused by an ongoing oil spill. Further, the drilling season limitation (the "shoulder season") ensures that adequate time is available to drill a relief well before the end of open water season. The same season relief rig adds to the rulemaking benefits through potential avoided spill costs.

Without the rule's SCCE and relief rig provisions, an oil spill in the Arctic could flow for more than 300 days until the next open water season. This regulation protects against this remote possibility and maximizes the likelihood that any well control event can be controlled and contained within a single season. These provisions have the potential to provide substantial benefits through avoided costs by shortening the duration of a potential catastrophic oil spill. The SCCE and relief rig requirements could turn a 300 day oil spill into a shorter event potentially saving more than $100 billion dollars in spill response and natural resource damages.

Exhibit 29 summarizes the potential avoided oil spill costs (i.e., the potential benefits) of the different spill control mechanisms of the rule. The first column lists the different spill control mechanisms which are designed to reduce the duration of a catastrophic spill. As described, the capping stack is required to be in position within 24 hours of a loss of well control event and would take approximately 6 hours to deploy, meaning a spill could be contained within 30 hours (or 1.25 days). Using the worst case discharge volumes and per barrel costs from Exhibit 27, a possible catastrophic spill controlled by the capping stack would cost approximately $440 million to $1 billion. Alternatively, without the capping stack requirement the hypothetical worst case spill (as shown in the fourth column) would cost between $39 and $129 billion. Such a spill is estimated to last approximately 200-313 days (as shown in Exhibit

29), spilling approximately 5 million barrels. Under these assumptions, if a spill were to occur, the potential avoided cost (or potential benefits) of the capping stack requirement range from $38 to $128 billion. The next row shows the similar results for the cap and flow and containment dome requirements. These systems are required to be on location within 7 days and could take up to two days to deploy. If the capping stack was unsuccessful, but these were successful, the spill could be controlled within 9 days. Again, compared to a worst case situation where equipment is required to be transported from other regions, this requirement leads to substantial benefits of the rule. Finally, as shown in the last row, the relief rig requirement is designed to permanently stop the flow of hydrocarbons within 34 days. Even under this scenario, the relief rig requirement still provides $34 to $107 billion in benefits from reducing the duration of a spill, should one occur.

Exhibit 29: Potential Avoided Spill Costs by Spill Control Mechanism

Spill Control Mechanism	Spill Duration (days)	Possible Spill Cost ($ billions)	Hypothetical Worst Case Spill* ($ billions)	Potential Avoided Cost (Potential Benefits) ($ billions)
Capping Stack	1.25	$0.44 - $1.09	$38.54 - $129.04	$38.1 - $127.95
Cap and Flow/Containment Dome	9	$1.39 - $6.08	$38.54 - $129.04	$37.15 - $122.96
Relief Rig	34	$4.45 - $22.17	$38.54 - $129.04	$34.09 - $106.86

*This spill is considered worst case as it assumes the oil spill lasts the entire ice season. As shown in Exhibit 28, this is approximately a 200-313 day spill of approximately 5 million barrels. As shown in Exhibit 25, this size spill is estimated to have a frequency of approximately 0.00121 for every 50 OCS wells drilled.

7.2.4.1.1 Non-monetized Catastrophic Oil Spill Costs

The cost estimates in Exhibits 28 and 29 represent the Arctic use values that can be monetized in the estimate of a catastrophic oil spill cost. However, another category of benefits exists with the potential for very large additional values in the Arctic. These are known as non-use values. Non-use values, also known as passive-use values, are values not associated with actual resource use. One common non-use value is existence value, or the value individuals place on ecosystem health and environmental amenities.

Individuals benefit from non-use value by simply knowing that these assets and services exist and will be preserved and protected in the region, even if those same individuals do not intend to visit the region. For example, some people attribute an existence value to knowing that the Alaskan wilderness exists and is pristine, even though they are likely never to go there. Another non-use value is bequest value, the value people place on the preservation of the regions' environmental amenities for future generations, even if the individuals do not intend to use the resource themselves.

Monetizing these non-use values is difficult because they are not traded in markets and their values can be highly subjective. One way these non-use values are occasionally monetized is through contingent valuation surveys. In these surveys, the public is asked how much they would be willing to pay or accept for a change in quality of certain environmental services, given their income and wealth constraints. Including non-use values would increase the rule's benefit of reducing the risk of a catastrophic oil spill.

To obtain an estimate of the non-use values associated with this rule and with further protecting the Arctic, we adopted the benefit-transfer approach and used an empirical estimate of non-use value from a contingent valuation study conducted after the Exxon Valdez oil spill. Respondents were asked how much they would be willing to pay to avoid a future oil spill in the Prince William Sound with damage equivalent to that the Exxon Valdez oil spill caused. This study found that the median willingness to pay value per U.S. household was $78 (adjusted to 2014 dollars) to avoid another Exxon Valdez type oil spill (Carson et al 2003). If we assume this same value is applicable to the U.S. Arctic and assume the value applies to the approximately 116 million U.S. households, the total willingness to pay to avoid another catastrophic oil spill would be over $9 billion, an amount which is much higher than the estimated compliance costs associated with reducing the risk of a catastrophic oil spill. The magnitude of this non-use value estimate shows the importance the public places on the Alaska region and its desire to have it remain environmentally protected.

Given the subjectivity and timing of the noted contingent valuation study, we have not included the resulting estimate in a monetized calculation of benefits from any of the rule's provisions. Instead, the estimate provides an important data point to consider in evaluating the benefits of this rule. The public desires a protected Arctic and places a large value on avoiding a catastrophic oil spill in the Arctic. Because we are unable to monetize all aspects of the consequences of an oil spill, the estimates discussed in Section 7.2.4.1 capture only part of the value to society from mitigating the consequences of a catastrophic oil spill.

7.3 Summary of the Costs and Benefits of the Rule's Provisions

This rule's new provisions require that operators provide additional information to Federal agencies. The rule also will further protect fragile Arctic natural resources and help reduce the risk and duration of a catastrophic oil spill. The new provisions of the rule add $2,047.6 million under 3-percent discounting over ten years and $233.98 million in 10-year average annual costs. Given the difficulties in estimating a total benefit from the rule, we have considered the different provisions and their benefits individually.

The potential impact and cost (described in 7.2.4.1) of an Arctic OCS oil spill is substantial. This rule's required spill control mechanisms provide significant potential benefits through avoided spill costs. BOEM and BSEE have determined that the substantial quantitative and qualitative benefits of the rule's new provisions justify the additional costs.

8. Discussion of Non-monetized Impacts

Some of the comments received during the public comment period suggest BOEM and BSEE consider additional non-monetized impacts of the rule. Commenters were concerned that the rule might lead to reduced Arctic exploration and development.

Though the ultimate impact on long-run production is unknown, BOEM and BSEE acknowledge that the requirements contained in the rule may affect the pace of exploration and development of Arctic oil and gas resources. The extent of Arctic hydrocarbon deposits can only be determined with certainty through drilling. If this regulation slows the pace of exploration beyond the status quo, it may ultimately take longer to bring economic deposits of hydrocarbons into production. This may affect the rate of job creation and the generation of revenues. This is especially true if existing Arctic production falls below the minimum TAPS (Trans-Alaska Pipeline System) throughput and the pipeline is shut-in.[59] The pace of exploration and production may also affect national energy security, but any such impacts are subject to many different variables and are difficult to quantify. Additionally, the finalized regulations provide a clear pathway for alternate compliance measures to be utilized. The ability of an operator to drill multiple exploratory wells in a single season may be enhanced if well intervention technology is developed that meets or exceeds the level of safety and environmental compliance required by BSEE regulations. For example, future well intervention technology that will be able to kill and permanently plug an out-of-control well could eliminate the need for an Arctic drilling shoulder season and relief well capabilities. BOEM and BSEE further note that any resources not developed currently will be available for future discovery and development. In the future, the addition of Arctic OCS production could help fulfil the necessary capacity of the TAPS pipeline.[60]

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.

[59] Continued TAPS operation is an important economic consideration for potential Arctic OCS oil discoveries and onshore Arctic oil.

[60] If the TAPS pipeline is no longer available when Arctic OCS production begins, oil would likely have to be tankered out of the region. While tankering oil out of the Arctic could be allowed, it is likely to be much more expensive than TAPS, since oil must be stored most of the year.

BOEM and BSEE also considered whether the regulation might adversely affect Alaska employment by reducing the potential for jobs associated with the offshore oil and gas industry. EO 13563 requires an analysis of employment impacts. The Arctic region of Alaska has not relied previously on 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. When considering the cumulative impacts of Arctic specific provisions in this rule, the Bureaus considered the fact that reduced employment might occur. However, the rule brings potential benefits to the local economy and cultural traditions from reduced risk of spills. A catastrophic oil spill would have negative economic impacts far beyond the OCS oil and gas industry, including the disruption of subsistence whaling on which Alaska Natives rely for food and for their cultural identity. Similarly, certain provisions of the rule could give rise to additional employment opportunities related to equipment and services required by the rule. 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.

9. Conclusion

This rule adds new provisions to the current Arctic OCS regulatory requirements and codifies existing requirements which are current practice and industry standards. Together, these provisions will provide substantial benefits for ensuring safety and environmental protection during Arctic OCS exploration drilling operations. This rule will reduce both the overall risk of oil spills on the Arctic OCS and the consequences of a spill if one were to occur as well as providing certainty to industry and assurance to stakeholders. Given the nature of the different types of benefits, we were not able to present a standard analysis of the costs and benefits associated with this rule. However, we did quantify all of the costs and identified important benefit measures. We supplemented this analysis with a discussion on baseline catastrophic oil spill risk and an estimate of catastrophic oil spill costs.

Exhibit 30 summarizes the total costs of the rule by numbered year using discount rates of 3 percent and 7 percent. Similar to the analyses presented above, the summation of the individual cost items in Exhibit 30 might not equal the total shown, due to rounding.

Exhibit 30. Summary of Total Monetized Costs

Year	Total Costs of Rule ($ millions)
	A
1	$0.55
2	$395.79
3	$113.65
4	$492.93
5	$222.81
6	$222.81
7	$222.81
8	$222.81
9	$222.81
10	$222.81
Undiscounted 10-year total	$2,339.76
Present value 10-year total with 3% discounting	$2,047.60
Present value 10-year total with 7% discounting	$1,739.01
Average Annual (years 1 - 10)	$233.98

Exhibit 31 presents the same total costs (discounted at 3 percent) by provision along with the primary benefit of each component.

Exhibit 31. Regulatory Provisions, Costs, and Benefits[61]

Provision	Rule Cost (Discounted at 3% over 10 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	*	Reduces risk of a spill
(d) Real-time Monitoring Requirements	**	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
(m) Industry Familiarization with the New Rule	$0.37	General
Total	**$2,047.60**	

** The drilling of mudline cellars has been a longstanding practice in the Chukchi and Beaufort Seas extending back to the 1980s, thus this provision is assigned to the regulatory baseline.*
***The BSEE Well Control rule at § 250.724 requires real-time monitoring for all operations with a subsea BOP or surface BOP on a floating facility. Thus, the cost for this provision is assigned to the regulatory baseline.*

[61] Note that former provision (d) from the NPRM: Stipulating the frequency of blowout preventer pressure tests, was removed from this rule. Related requirements will be addressed in the BSEE Blowout Preventer Systems and Well Control, 1014–AA11 rulemaking.

Although the underlying risk of a catastrophic oil spill in the Arctic is low, BOEM and BSEE have determined that the economic, environmental, ecological, sociocultural cost to the Nation from such a spill warrants regulatory action to prevent a spill, reduce the risk of a spill, or to decrease the duration or severity of a spill should one occur. Moreover, given the sets of both quantifiable and unquantifiable benefits discussed in this RIA, BOEM and BSEE deem the rule cost-beneficial and conclude that proceeding with this rule is appropriate.

10. UMRA

This rulemaking 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. The Final RIA for this rulemaking and the rule itself address applicable requirements of the UMRA, 2 U.S.C. 1501 *et seq*.

Among other things, the rulemaking and the Final RIA:

(1) Identify the provisions of the Federal law (Outer Continental Shelf Lands Act and Oil Pollution Act) under which this rule is being enacted;

(2) Include a quantitative assessment of the anticipated costs to the private sector (i.e., expenditures on labor and equipment) of the rule (included in Sections 5, 6 and 7); and

(3) Include qualitative and quantitative assessments of the anticipated benefits of the rule (included in Section 7).

In addition, because all anticipated expenditures by the private sector analyzed in the final RIA will be borne by the OCS oil and gas exploration industry in the Arctic OCS region, the Final RIA analysis satisfies the UMRA requirement to estimate any disproportionate budgetary effects of the Final Rule on a particular segment of the private sector.

Furthermore, the Final RIA describes BOEM's and BSEE's consideration of two major regulatory alternatives for dealing with the safety and environmental concerns raised by exploration activities on the Arctic OCS (included in Section 3). BOEM and BSEE have decided to move forward with this rule, in lieu of the other alternative, because the other alternative would not address as efficiently or effectively the safety, environmental, or sociocultural concerns raised by various stakeholders on the Arctic OCS or achieve the objectives of this Final Rule.

The rule will not impose any unfunded mandates or any other requirements on State, local, or tribal governments; thus, the rulemaking will not have disproportionate budgetary effects on such governments. Assuming, however, that the rule might result in budgetary effects on the Arctic OCS area, BOEM and BSEE have determined that accurately estimating such effects is not reasonably feasible. The impacts of this rulemaking would have, at most, secondary budget effects for State, local, or tribal governments. A variety of other circumstances (e.g., the price of oil, each operator's overall financial health, and the prospects of success of any exploratory drilling) would have a far greater impact on the decisions made by regulated (or unregulated entities) that could in turn affect the budget of State, local, or tribal governments far more than this rule. Because the ways these other circumstances could affect State, local, or tribal governments' budgets are variable and unpredictable, estimating how any of those circumstances would affect an entity's future decisions, or what impacts, if any, such decisions could have on future budgets of these governments is not feasible.

Similarly, BOEM and BSEE have determined that accurately estimating the potential effects, if any, of the rule on the national economy (e.g., productivity, economic growth, employment, international competitiveness) is not reasonably feasible, and they are likely to be minimal. The rule will affect only exploratory drilling activities on the Arctic OCS, and any potential impact on the national economy will depend on individual business decisions made by regulated entities (e.g., whether or not to hire new employees).

Appendix: Baseline Provisions

Section 7 considered the costs and benefits of the rule's new provisions. However, as discussed in Section 5, there are additional provisions of this rule which are considered part of the regulatory baseline. As such, they are not included as costs of the rule's provisions. These provisions are consistent with existing Arctic practice, regulations, and industry standards, and clarify the Arctic-specific exploration requirements. In codifying these requirements and industry standards, the rule helps provide certainty to stakeholders of the requirements for Arctic OCS exploration drilling operations. Recognizing that these regulations codify existing requirements and standards, we present the costs and potential benefits of these current requirements in this appendix.

A1. Cost of the Rule's Baseline Provisions

The following provisions, codified in the regulations, have been identified as having baseline costs that are appropriately included in this section.

(c) Additional Requirements for Securing Wells

(d) Real-time Monitoring Requirements

A.1.1 Additional Requirements for Securing Wells

Section 250.720(c) includes the requirements for securing wells during exploratory drilling operations on the Arctic OCS. Operators that move a drilling rig off a well prior to completion or permanent abandonment are required to ensure that any equipment left on, near, or in a well bore that has penetrated below the surface casing is positioned to protect the well head and prevent or minimize the likelihood of compromising the down-hole integrity of the well or well plug effectiveness. Additionally, in areas of ice scour operators will be required to use a well cellar or an equivalent means of minimizing the risk of damage to the wellhead.[62] These requirements will help reduce the risk associated with damage to the well or to equipment associated with ice floe or other potential sources of damage. Since this provision is already required by current regulations and is clarified in this rule, the requirements do not result in new compliance costs. These compliance costs are part of the baseline cost of current Arctic regulations (§ 250.451(h)) and also best practices with which industry must comply. The agencies recognize that this is a cost likely necessary for operating in the Arctic, regardless of any regulatory requirement. To acknowledge the costs of Arctic regulations, we have examined the cost of well cellar drilling as part of the baseline.

In calculating the baseline cost associated with this provision, we updated our cost assumptions based on improved information provided in comments and based on the actual duration for drilling a well cellar. The current requirement that a mudline cellar be drilled with every exploration well in areas of ice scour costs operators drilling time, additional materials, and associated maintenance.

We calculated the costs of drilling based on the number of days of drilling time that would be required to drill or construct the cellar and an estimated per day cost of drilling. 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 assume that the average daily drilling cost is as described in Section 6. These calculations resulted in a drilling cost of approximately $36.75 million per well.[63]

The well cellar requirement imposes an additional capital cost per drilling rig (for the mudline well cellar drill bit) and a maintenance cost (for upkeep of the drill bit). Using costs received in comments, we assume that the drill bit will cost $15 million for each of the four drilling rigs with an annual maintenance cost of $7 million. We assume that the maintenance cost is not required in the year the drill bit is first used. Exhibit A1 summarizes the annual costs of the additional requirements for securing wells.

[62] A well cellar is a hole excavated in the seafloor that can house wellhead equipment to provide protection against damage from ice that scours the seafloor.
[63] The daily rig operating costs vary by year depending on the number of other drilling vessels that can share certain supply vessels.

Exhibit A1. Annual Additional Requirements for Securing Wells (§ 250.720) ($ millions)

	Number of Wells	Drilling Cost per Well	Well Cellar Capital Cost	Well Cellar Maintenance Cost	Annual Cost
Year	A	B	C	D	E = (A × B) + C + D
1	0	$0.00	$0.00	$0.00	$0.00
2	4	$36.75	$30.00	$0.00	$176.99
3	4	$36.75	$0.00	$14.00	$160.99
4	6	$36.75	$30.00	$14.00	$264.49
5+	6	$36.75	$0.00	$28.00	$248.49

A.1.2 Real-time Monitoring Requirements

We calculated the annual labor and equipment cost to industry associated with the real time monitoring requirements by multiplying the assumed average daily cost per rig to comply with these requirements by the number of operating days per year and then added an initial system cost and a refurbishing cost (which occurs every 3 years), based on industry input.[64, 65] Exhibit A2 summarizes the annual costs of the real-time monitoring and associated reporting requirements.

[64] The real-time monitoring estimate contains both the industry-reporting burden and the capital needs for the requirement. The paperwork reduction analysis estimate for this provision includes only the industry-reporting burden and is a subset of this estimate.

[65] We assume that the real time monitoring system on a rig on the Arctic OCS would operate for 126 days per year which includes the 82 day drilling season, plus 30 days for set-up and 14 days for take-down at the end of the season. We assume that the average daily cost associated with these monitoring requirements will be $5,000, including equipment and labor. Based on industry input, a $400,000 initial system cost and a $200,000 refurbishing cost, incurred every 3 years, are assumed in the cost estimate.

Exhibit A2. Annual Real-time Monitoring Requirements (§ 250.452)

	Number of Operators	Number of New Operators	Per Season Cost per Operator	Purchase Cost per New Operator	Refurbish Cost	Annual Cost
Year	**A**	**B**	**C**	**D**	**E**	**F = (A × C) + (B × D) + E**
1	0	0	$630,000	$400,000	$0	$0
2	1	1	$630,000	$400,000	$0	$1,030,000
3	1	0	$630,000	$400,000	$0	$630,000
4	3	2	$630,000	$400,000	$0	$2,690,000
5	3	0	$630,000	$400,000	$200,000	$2,090,000
6	3	0	$630,000	$400,000	$0	$1,890,000
7	3	0	$630,000	$400,000	$400,000	$2,290,000
8	3	0	$630,000	$400,000	$200,000	$2,090,000
9	3	0	$630,000	$400,000	$0	$1,890,000
10	3	0	$630,000	$400,000	$0	$1,890,000

A2. Baseline Benefits: Reducing the Risk of a Catastrophic Oil Spill

Both the provision for real-time monitoring and the additional requirements for securing wells help reduce the risk of a catastrophic oil spill from Arctic OCS exploration activities. The magnitude of these benefits, however, is uncertain and highly dependent on the actual reduction in the probability of incidents. 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. Section 7.2.3.1 provides more details on the estimated catastrophic oil spill risk.

The consequences of an oil spill depend on several factors, including the type and amount of oil, the location of the spill, the areal distribution of the release, the sensitivity of the ecosystem affected, and the weather. See Section 7.2.4.1 for an estimate of the range of costs possible from a catastrophic oil spill.

The costs of the two baseline provisions of the rule which reduce the risk of a catastrophic oil spill are estimated to be $1.8 billion at 3 percent discounting and $1.5 billion at 7 percent discounting over the 10 years of the analysis period. If these regulatory provisions were able to prevent a catastrophic oil spill that would otherwise occur, the benefits of the avoided spill costs have the potential to far exceed the costs of compliance with the provisions. Although the probability of a catastrophic spill is very small, the *Deepwater Horizon* oil spill demonstrated that such low probability events can occur and do have devastating economic and environmental consequences. To provide assurances to stakeholders and partners that such an event will be avoided or mitigated in the future, BOEM and BSEE have determined that proceeding with this rule is appropriate.

A3. Summary of the Costs and Benefits of the Baseline Provisions

Exhibits A3 and A4 summarize the cost analysis of the baseline costs of the rule. Exhibit A3 summarizes the 10-year average annual costs (undiscounted) for the baseline rule costs. Exhibit A4 summarizes the baseline costs using discount rates of 3 percent and 7 percent. Similar to the analyses presented above, the summation of the individual cost items in Exhibit A3 and Exhibit A4 might not equal the total shown, due to rounding.

Exhibit A3. 8 Year Average Annual Baseline Costs by Provision (with no discounting)

Provision	10-year Average Annual Costs: Standard Baseline
(c) Additional Requirements for Securing Wells	$ 210,845,116
(e) Real-time Monitoring Requirements	$ 1,649,000
TOTAL	**$ 212,494,116**

Exhibit A4. Summary of Monetized Baseline Costs[1]

Year	Industry Costs	Government Costs	Total Costs
	A	B	C = A + B
1	$0.0	$0	$0.0
2	$185.6	$0	$185.6
3	$169.2	$0	$169.2
4	$267.2	$0	$267.2
5	$250.6	$0	$250.6
6	$250.4	$0	$250.4
7	$250.8	$0	$250.8
8	$250.6	$0	$250.6
9	$250.4	$0	$250.4
10	$250.4	$0	$250.4
Undiscounted 10-year total	**$2,124.9**	**$0**	**$2,124.9**
Present value 10-year total with 3% discounting	**$1,826.0**	**$0**	**$1,826.0**
Present value 10-year total with 7% discounting	**$1,514.0**	**$0**	**$1,514.0**
Average Annual (years 1-10)	**$212.5**	**$0**	**$212.5**