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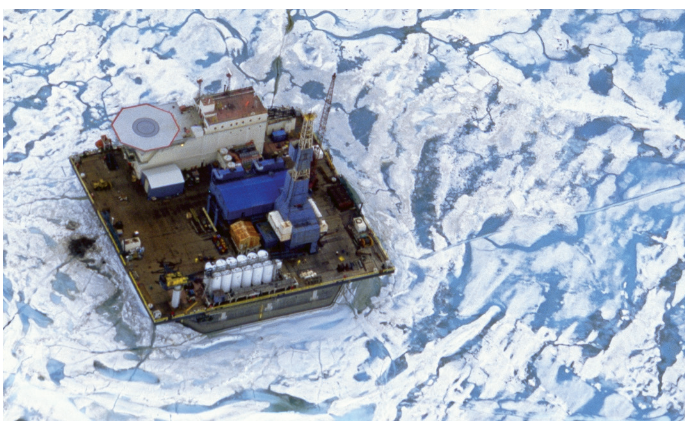

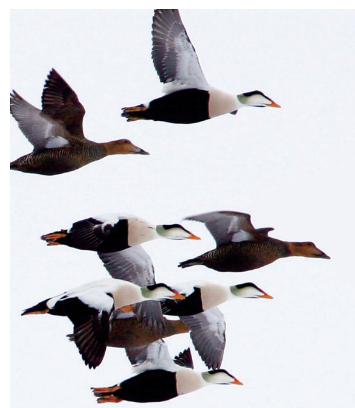

Arctic Standards

Recommendations on Oil Spill Prevention, Response, and Safety in the U.S. Arctic Ocean

Contents

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For more information about Pew's Arctic work, please see www.pewenvironment/arctic.

1

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Overview

The search for oil is reaching into ever more remote corners of the world, including the U.S. Arctic Ocean. Diminishing sea ice is opening Arctic waters to increased industrial activities such as shipping and oil and gas development. Yet industrial development in these waters brings a new set of challenges and a larger set of risks than in other oceans because, in the Arctic, people and machinery will be working in some of the most remote and harshest conditions on the planet. The Arctic Ocean is ice-covered for eight to nine months of the year, with almost complete darkness for nearly three of those months. Even during the summer when the ice pack has mostly receded, the Arctic still experiences high seas, wind, freezing temperatures, dense fog, and floating ice hazards.

Anyone doing business in the Arctic needs to be prepared for self-rescue. Inadequate infrastructure and punishing weather could seriously delay the arrival of additional vessels, equipment, people, or other help. Major highways, airports, and ports that most Americans take for granted do not exist in the Arctic. The nearest U.S. Coast Guard air base is in Kodiak, AK, more than 950 air miles away. The nearest major port is in Dutch Harbor, AK, which is over 1,000 miles from the Arctic Ocean. Sailing from Dutch Harbor to Barrow, AK (the point between the Chukchi and Beaufort seas in the Arctic Ocean), would be similar to transiting the entire West Coast of the United States.

Oil spilled in Arctic waters would be particularly difficult to remove. Current technology has not been proved to effectively clean up oil when mixed with ice or when trapped under ice. An oil spill would have a profoundly adverse impact on the rich and complex ecosystem found nowhere else in the United States. The Arctic Ocean is home to bowhead, beluga, and gray whales; walruses; polar bears; and other magnificent marine mammals, as well as millions of migratory birds. A healthy ocean is important for these species and integral to the continuation of hunting and fishing traditions practiced by Alaska Native communities for thousands of years.

The Outer Continental Shelf, or OCS, of the U.S. Arctic Ocean, which includes the Chukchi and Beaufort seas off the northern and northwestern coast of Alaska and extends from 3 to 200 nautical miles offshore, contains oil and gas resources managed by the U.S. Department of the Interior. (State and local governments manage offshore resources from the shoreline to 3 nautical miles offshore. This report does not address oil and gas exploration, development, or production in onshore areas of the Arctic or the nearshore state waters.) Within the OCS, the Interior Department is responsible for:

- Developing and implementing an oil and gas leasing program.
- Completing environmental impact statements and environmental assessments on proposed oil and gas projects.
- Approving and providing oversight of exploration, development, and production plans for oil and gas projects.

In short, the Interior Department is obligated to examine the potential environmental impact of its leasing program, ensure approved plans are executed safely and in the best interest of the United States, and balance the benefits and risks of oil and gas development. (See Figure 1, a flow chart showing the basic exploration, development, and production process.)

A majority of the OCS offshore oil and gas exploration, development, and production in the United States takes place in the Gulf of Mexico. As a result, most of the drilling and extraction technology is developed for and tested in temperate waters.

In the wake of the 2010 Deepwater Horizon blowout in the Gulf of Mexico, however, the United States and

Figure 1[1]

The Offshore Oil and Gas Exploration, Development, and Production Process

The flow chart shows a simplified view of the process, with each step requiring a set of additional permits and approvals

Source: U.S. Department of the Interior

other Arctic countries such as Canada and Greenland examined whether regulatory standards for Arctic oil and gas exploration, development, and production were sufficient to prevent a similar disaster and whether there was capability to respond to a major oil spill in ice-infested waters. The United States chartered a committee, the Ocean Energy Safety Advisory Committee, to examine U.S. regulations for OCS oil and gas operations and to make recommendations. In August 2012, the committee concluded that there is a need to modernize U.S. regulations to include Arctic-specific standards to prevent oil spills, contain them, and respond to them quickly and effectively.[2]

On March 14, 2013, Secretary of the Interior Ken Salazar released a formal review of Shell's 2012 Alaska offshore oil and gas exploration program.[3] The Interior Department's findings reinforce the importance of taking a regionally specific approach to offshore oil and gas exploration in the Arctic. The report concluded that the federal government must recognize and account for the unique challenges of this region, which not only holds energy potential, but also has extreme environmental and climate conditions, limited infrastructure, and the subsistence needs of Alaska's North Slope indigenous communities to consider. In June 2013, Interior began a public process to solicit input on improved Arctic technology and equipment standards for exploration, development, and production with a goal of proposing new regulations in late 2013 and 2014. Such regulations must carefully balance responsible energy development with the protection of important environmental and subsistence resources.

To aid the United States in its efforts to modernize Arctic technology and equipment standards, this report examines the fierce Arctic conditions in which offshore oil and gas operations could take place and then offers a summary of key recommendations for the Interior Department to consider as it develops world-class, Arctic-specific regulatory standards for these activities. Pew's recommendations call for improved technology, equipment, and procedural requirements that match the challenging conditions in the Arctic and for full public participation and transparency throughout the decision-making process. Pew is not opposed to offshore drilling, but a balance must be achieved between responsible energy development and protection of the environment. It is essential that appropriate standards be in place for safety and for oil spill prevention and response in this extreme, remote, and vulnerable ecosystem. This report recommends updating regulations to include Arctic-specific requirements and codifying temporary guidance into regulation.

The appendixes to this report provide substantially more detail on the report's recommendations, including technical background documentation and additional referenced materials. Please refer to the full set of appendixes for a complete set of recommendations. This report and its appendixes offer guidelines for responsible hydrocarbon development in the U.S. Arctic Ocean.

What are Arctic standards?

Arctic OCS standards would provide consistent requirements on how to design, build, install, and operate equipment to safely explore and develop oil and gas resources and respond to accidents in the region using best Arctic science, technology, and practices. Arctic standards should account for the area's remote location, lack of infrastructure, and unique operating conditions due to the severe and changing climate to ensure that oil spills are prevented and the capability exists to respond to a worst-case oil spill.

The Arctic poses engineering design and operating challenges that are not present in other parts of the U.S. OCS. To meet these challenges, these are some of the changes that Pew recommends:

- Arctic offshore drilling operations into hydrocarbon-bearing zones should be limited to periods when the drilling rig and its associated spill-response system are capable of working and cleaning up a spill in Arctic conditions.
- Vessels, drilling rigs, and facilities should be built to withstand maximum ice forces and sea states that may be encountered.
- Equipment needed to control a spill, such as relief rigs and well control containment systems, should be designed for and located in Alaska's Arctic so they can be readily deployed.
- Spill response equipment should be located in Alaska's Arctic and be sufficiently robust to remove oil caught in ice-infested waters and trapped under ice.
- Redundant systems—including blowout preventers, double-walled pipelines, double-bottom tanks, and remotely operated controls—should be installed because equipment and logistical access is unavailable for large parts of the year due to harsh weather or ice cover.

To achieve these goals, the Interior Department should develop a combination of prescriptive and performance-based Arctic OCS standards to regulate the offshore oil and gas industry. Prescriptive standards set minimum technology and operating benchmarks based on proven, tested, and generally accepted best industry technology and practices. Prescriptive standards create less complex approval processes for regulators. Because prescriptive standards may become less effective as new technology and practices are developed, the Interior Department should routinely update minimum prescriptive standards to ensure that technical innovations are routinely integrated into regulation. Industry can propose alternatives that exceed the minimum requirement at any time, allowing industry to voluntarily advance technology without delay. However, alternative proposals should be subject to close regulatory review, and third-party experts should be consulted to ensure that the alternative meets or exceeds the minimum prescriptive standard.

Performance-based standards allow the operator flexibility and encourage the development of new technologies. But these standards are not always efficient and they require regulators to have substantially more time and expertise to ensure the desired objective is achieved. Here again, third-party experts should be consulted. Because of the additional study, time, and decision-making required with performance-based standards, a regulatory system based on a mix of prescriptive and performance-based standards is preferred.

Principles to guide Arctic policy and management decisions

Decisions about whether, where, and how oil and gas exploration and production activities are conducted in the U.S. Arctic Ocean should be based on sound scientific information, thorough planning, the best available technology, and full involvement of the communities most affected. A balanced and careful approach to development must account for environmental protection and the social, cultural, and subsistence needs of Alaska communities. Specifically, Arctic policy and management decisions should be based on three core principles:

- Ensure that local communities have a meaningful voice in decision-making.
- Safeguard ecosystem health and the subsistence way of life.
- Require that science guide decision-making.

We'll briefly detail these principles before turning to the main pages of the report.

Ensure that local communities have a meaningful voice in decision-making.

Arctic indigenous residents have valuable knowledge about their home and its resources, which can help inform planning and decision-making. Their experience and traditional way of life—passed down through many generations—have given them great knowledge of their environment and the species with which they share it.

Gathering and using indigenous residents' traditional knowledge[4] will require both a precautionary and adaptive approach. The federal government should make a better effort to ensure that traditional knowledge truly informs decision-making about the Arctic environment. To be meaningful, traditional knowledge should be incorporated before committing to management decisions that may adversely affect subsistence resources. Arctic peoples' ocean-based subsistence activities are central to their culture and sense of identity.

In the end, Arctic residents must live with the consequences of policy and management decisions. For all these reasons, the federal government must ensure meaningful opportunities for participation by local communities, governments, tribes, co-management organizations, Alaska Native Claims Settlement Act corporations, and similar Alaska Native organizations. The federal government is required to consult fully with Alaska Native tribes on a government-to-government basis. Any governance framework needs to incorporate consultation well in advance of management decisions and include a strategy for sharing information and providing feedback about indigenous residents' concerns.

Safeguard ecosystem health and a subsistence way of life.

The U.S. Arctic Ocean is unique. Sea ice covers the Chukchi and Beaufort seas for much of the year. The region is subject to severe weather, but it is also remarkably productive. Fish and wildlife—including a wide variety of marine mammals and seabirds—make extensive use of the area. Indigenous residents of Arctic communities are an integral part of the region's rich ecosystem.

Areas within the ecosystem are not equal in ecological terms; some areas contribute disproportionately to ecosystem structure and functioning. Important ecological areas may include parts of the ocean that are used for subsistence purposes; are important for maintaining habitat heterogeneity or the viability of a species; or support an ecosystem's health, including its productivity, biodiversity, or resilience. For example, the Chukchi Sea lead system along the northwestern Alaska coast serves as an essential corridor for migrating species such as bowhead whales, ice seals, waterfowl, and seabirds. Among scientists, there is general consensus that time or place restrictions designed to protect high-value habitat are one of the most effective means of reducing potential disturbances. The federal government needs to undertake a process to identify and protect sensitive marine habitats in the Chukchi and Beaufort seas and defer them from future oil and gas leasing.

Protecting sensitive habitats important for marine mammals and overall ecological functioning is vital to safeguarding the food security of Arctic indigenous peoples, because there is a direct connection between the continued health of the marine environment and the health of their food supply and cultural well-being. The Arctic Ocean has long provided a direct source of healthy foods for indigenous Arctic communities. Subsistence foods such as bowhead and beluga whales are high in nutritional value and protect against high blood pressure, obesity, diabetes, cardiovascular disease, and other maladies. Harming these subsistence foods by reducing their abundance or contaminating their habitats could decrease food security, encourage consumption of processed foods with less nutritional value, and deteriorate the cultural fabric of Alaska Native communities. This is why the federal government must take a careful look at potential consequences of oil and gas exploration, development, and production on these subsistence resources and ensure they are protected.

Require that science guide decision-making.

To make informed oil and gas management decisions, it will be critical to better understand the cumulative effects of climate change, ocean acidification, and industrial stresses on the marine environment, and how these stresses interact to affect the ecosystems, species, and people. Developing a vigorous and lasting research and monitoring program is essential to generating reliable information, including trends, and reducing gaps in knowledge about Arctic ecosystems when making leasing, exploration, and development decisions.

The federal government should recognize that for science to guide decision-making, a long-term monitoring program must be put in place and sustained to assess the cumulative effects of multiple, interacting stresses. Such stresses include changes in climate, along with noise and pollution from vessel traffic and drilling operations, which can disrupt habitat, migration patterns, and communications of whales and other marine mammals.

President Barack Obama's "Blueprint for a Secure Energy Future"[5] identifies oil and natural gas supplies as an important component of the nation's energy portfolio. As part of this all-of-the-above energy strategy, the administration is committed to proceeding with energy exploration and production in Alaska—but only cautiously, safely, and incorporating the best available science. The Interior Department must ensure that any drilling is safe and responsible, and that it uses the most advanced technology and operating practices; this includes meeting Arctic challenges in its regulatory program.

This report addresses a narrow portion of the federal Arctic offshore oil and gas regulatory program found in Title 30 of the Federal Code of Regulations, Parts 250, 254, and 550. Pew selected these Interior Department regulations because they are in the most urgent need of update for the Arctic. But after the Deepwater Horizon disaster, and as part of the federal government's commitment to developing Alaska's energy resources cautiously and subject to the highest safety and environmental standards, Pew urges all federal agencies with oversight responsibilities to thoroughly review their regulatory standards for other aspects of the offshore program and update regulations to integrate new science, technology, and lessons learned.

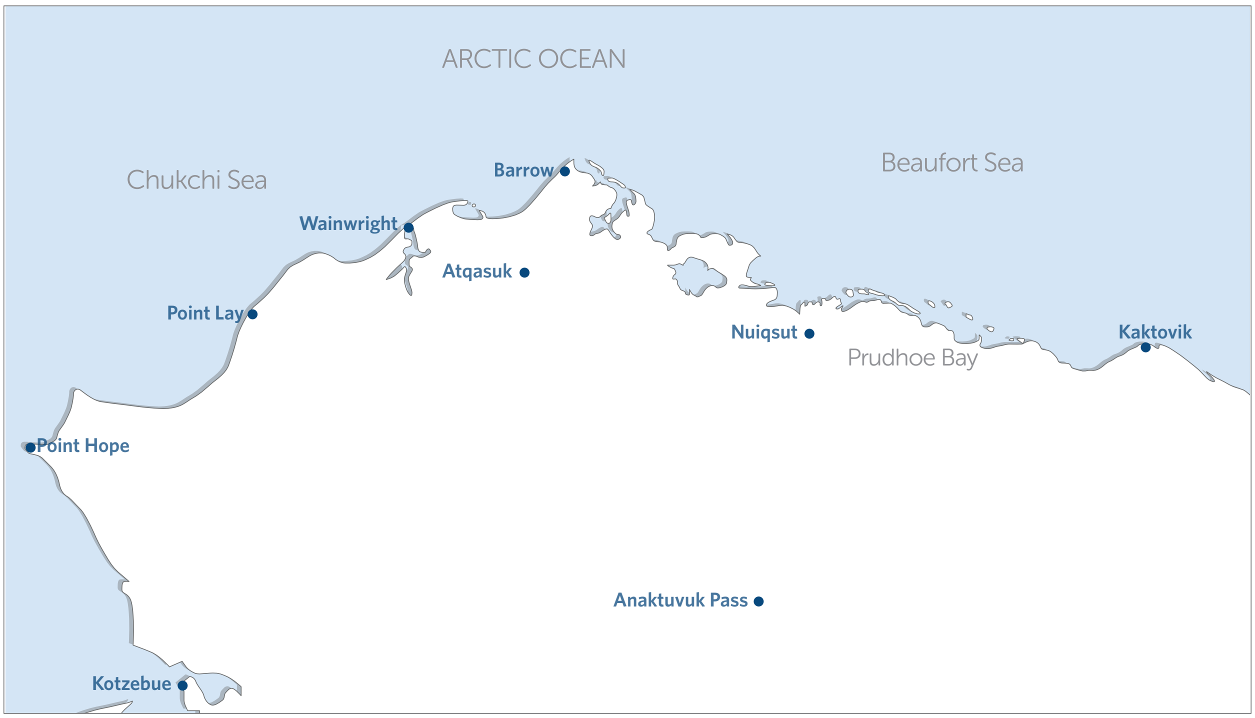
The Arctic Ocean

The Arctic Ocean is one of the world's last relatively untouched marine ecosystems, providing habitat for such important species as bowhead whales, walruses, ice seals, and polar bears. In this land of ice and snow, indigenous communities have thrived for millennia with a traditional way of life that is interwoven with the region's natural bounty. (See Figure 2.)

Figure 2[32]

Arctic Communities Along the Chukchi and Beaufort Seacoasts

Indigenous communities have thrived for millennia along the coast of what is now Alaska



Climate change is warming the Arctic at twice the rate of the rest of the planet,[6] causing a rapid melting of the ice pack and fundamentally altering this region's ecosystems. Compounding the effects of a changing climate are the consequences of greater industrial access to this region, including vessel traffic and oil and gas exploration, development, and production. The combination of the Arctic's remote location, scarce infrastructure, and difficult weather conditions could result in delay or compromise oil spill response operations in the event of an emergency.

Challenging conditions

The Arctic Ocean's seasonal weather is unlike any other OCS oil and gas operating area in the United States. Even during the summer months, when sea ice is at its lowest extent, there is the potential for ice, dense fog, storms, high winds and waves, and freezing temperatures.[8]

Vessel icing from sea spray, as seen here on the NOAA research ship Miller Freeman, is a hazard for marine operations in high latitudes.

Sea ice

The Beaufort and Chukchi seas are usually frozen for eight to nine months of the year (November through June or July). Sea ice typically begins to melt in June and July, a period called "breakup." The U.S. Arctic Ocean is relatively free of ice from July through September—the "open-water season." In October (Beaufort Sea) and early November (Chukchi Sea), the ice begins to form again in a period called "freeze-up."

First-year ice is approximately 5.9 to 6.5 feet thick in the Beaufort Sea and 3.9 to 4.9 feet thick in the Chukchi Sea. Multiyear ice—ice that has survived at least two summer melt seasons—in the Beaufort and Chukchi seas range from 9.8 feet to several hundred feet thick. The Interior Department reports that pressure-ridge keels—the part of the ice ridge that is underwater—can be thick enough to gouge the seafloor to a depth of about 165 feet in some areas.[9] Sea ice can damage offshore structures and vessels, and limit transportation and resupply options.

Freezing temperatures

The mean summer temperature in Barrow, the community between the Chukchi and Beaufort seas, is 38 degrees Fahrenheit, dropping steadily in October to a mean of 11 and barely above zero in November.[10] During the winter, temperatures as low as minus 50 have been observed,[11] plunging even lower when wind chill is considered.

Freezing temperatures can obstruct equipment and people. Add high winds and waves, and vessels and equipment can become coated with ice, impairing their functioning. In October, vessel icing from sea spray can be the primary reason that vessels leave the region.[12]

Wind and waves

Decreasing ice extent in summer can lead to higher waves and storm surges because the wind travels over larger areas of open water, building momentum. Winds gain speed during the summer, reaching a peak in October,[13] with an increased risk of reaching 30 knots (35 mph) or more.[14] In Barrow, daily average wind speeds in October are 14 mph, with gusts of 67 mph.[15] In the Beaufort Sea, winds prevail from the east and northeast, and the 100-year maximum wind can top 98 knots (113 mph). In the Chukchi Sea, winds prevail from the northeast, and the 100-year maximum wind is estimated at upwards of 62 knots (71 mph).[16]

Based on traditional knowledge, expected maximum wave heights are 22.5 feet in the Beaufort Sea and 28.5 feet in the Chukchi Sea.[17] The U.S. Army Corps of Engineers estimated the maximum wave height for the nearshore Beaufort Sea area to be 20 feet,[18] and other scientists estimated wave heights of up to 30 feet in the deeper waters (up to 100 feet).[19] Interior's Bureau of Safety and Environmental Enforcement (formerly the Minerals Management Service) estimated a maximum wave height of 29 feet in the Chukchi Sea.[20] Wind and wave conditions can impede transportation and resupply options and hinder emergency response operations.

Fog and seasonal daylight

Fog is more common during open-water months as warmer air interacts with cold water. Barrow averages 15 days a month of fog, and 6.5 days a month of heavy fog, from June to October.[21] Fog can reduce the visibility of air and marine pilots conducting transportation, resupply, and emergency response operations.

The amount of daylight in the Arctic changes drastically during the year, with 24 hours of daylight from mid-May to mid-August. As summer passes into autumn, daylight decreases rapidly until the Arctic is in complete darkness from mid-November to mid-January. Seasonal darkness can limit operational and emergency response activities.

Oil spill response gap

The Arctic Ocean's weather conditions present a challenge to oil and gas operators and emergency response workers. When sea ice, wind, and visibility, among other physical conditions, exceed the operating limits of equipment, emergency response would be unsuccessful or impossible. We call this the oil spill response gap.

Identifying oil spill response gaps as part of project planning allows industry and regulators to implement adequate oil spill prevention and safety measures to reduce or eliminate the risk of an oil spill occurring when oil spill response is not possible or effective. (See Table 1.)

Table 1[22]

Environmental Factors That Determine Operational Limitations in the U.S. Arctic Ocean

Percentages of time when operating limits for response are reached because of the environment*

	Winter (Jan.-March)	Spring (April-June)	Summer (July-Sept.)	Fall (Oct.-Dec.)
Ice Condition	Solid (100%)	Solid (80%) Broken Ice (20%)	Broken Ice (60%) Open Water (40%)	Open Water (20%), Broken Ice (60%), Solid (20%)
Darkness	81%	21%	13%	77%
Wind	22%	13%	21%	33%
Fog	57%	58%	48%	55%
Temperature <-35 F	37%			4%

* Data are for Barrow and Wainwright, AK.

Source: Adapted from Nuka Research and Planning Group, Western Regional Climate Center, Alaska Clean Seas data

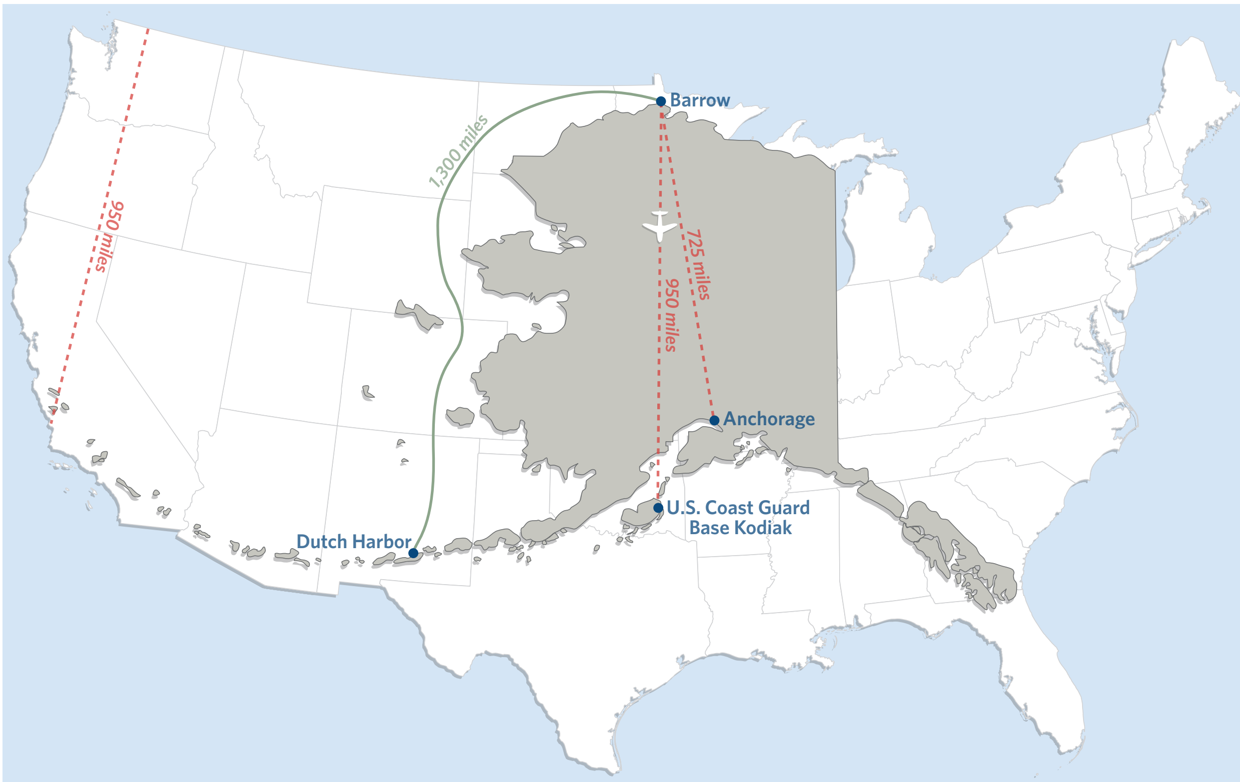
Limited infrastructure

Like much of Alaska, the coastlines of the Beaufort and Chukchi seas lack significant infrastructure such as major ports, airports, and roads. And the coastlines are more than 950 air miles from the nearest Coast Guard base in Kodiak and over 1,000 miles by sea from the nearest major port, in Dutch Harbor. (See Figure 3.) Only two airports (Barrow and Deadhorse) can handle cargo planes; however, those airports are connected only to small road and port systems capable of servicing a very small fraction of the Arctic coastline. There is minimal prepositioned oil spill-response equipment in Arctic communities or near sensitive ecological sites, leaving a vast amount of shoreline without protection. Transporting emergency responders and equipment to the Arctic offshore and nearshore, and getting them close to an oil spill, could be delayed by serious logistical challenges.

Figure 3[23]

Alaska's Size, Compared With the Lower 48 States

Distances by sea and air between key southern Alaskan cities and Arctic shores



Source: Nuka Research and Planning Group

Oil and gas leasing and exploration on the U.S. Arctic OCS

The Interior Department estimates that the U.S. Arctic OCS holds about 23 billion barrels of technically recoverable oil, with 15 billion in the Chukchi Sea and 8 billion in the Beaufort Sea.[24]

There has been limited exploration of the Arctic OCS, but with traditional sources of oil and gas decreasing, industry has been expanding efforts into frontier areas, including the Arctic Ocean.

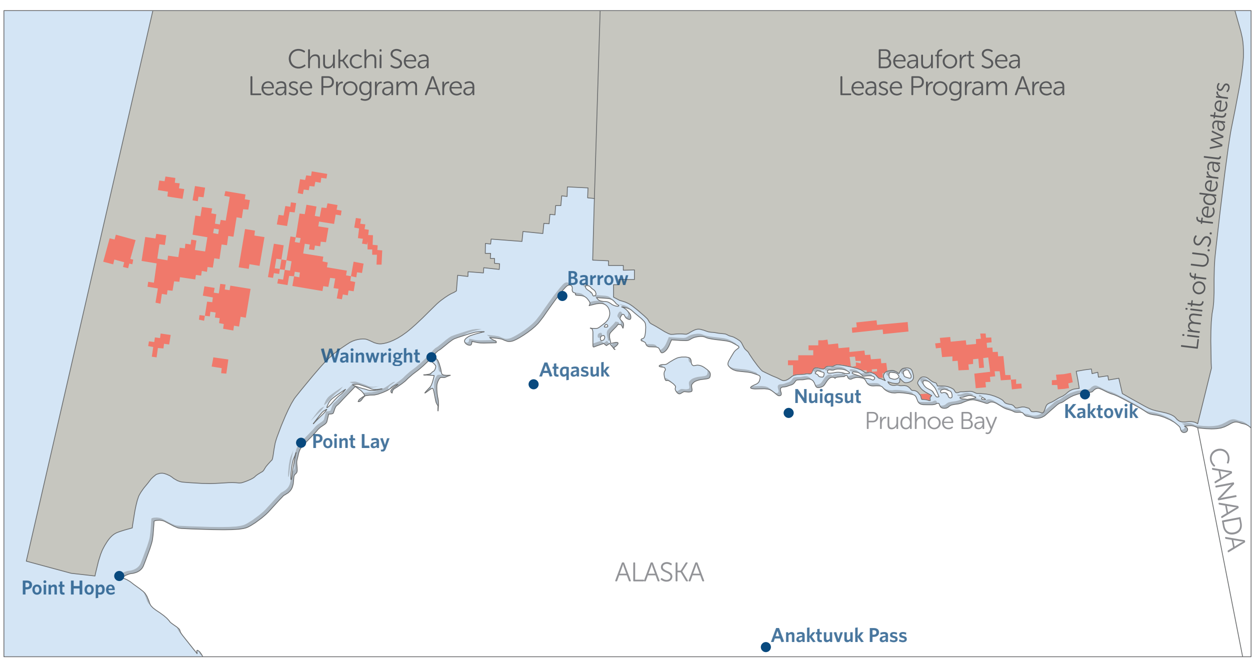
Since 1981, 30 exploration wells have been drilled in the federal waters of the Beaufort Sea. Five exploration wells were drilled in the Chukchi Sea's federal waters between 1989 and 1991.[25] More than 20 years later, several major oil and gas companies have active leases and either resumed exploration activity or have announced plans for the two seas. In 2001, oil production commenced from the BP Northstar field located in both the state and federal offshore waters of the Beaufort Sea, developed from a gravel island connected to shore by pipeline. No other Beaufort or Chukchi Sea OCS fields are in production.

The Chukchi Sea program area for 2012 to 2017 includes 55.11 million acres,[27] of which 2.7 million acres are leased.[28] The Beaufort Sea program area for the same period includes 64.72 million acres,[29] of which almost 1 million acres are leased.[30] (See Figure 4.)

Figure 4[26]

Federal Offshore Leasing Areas

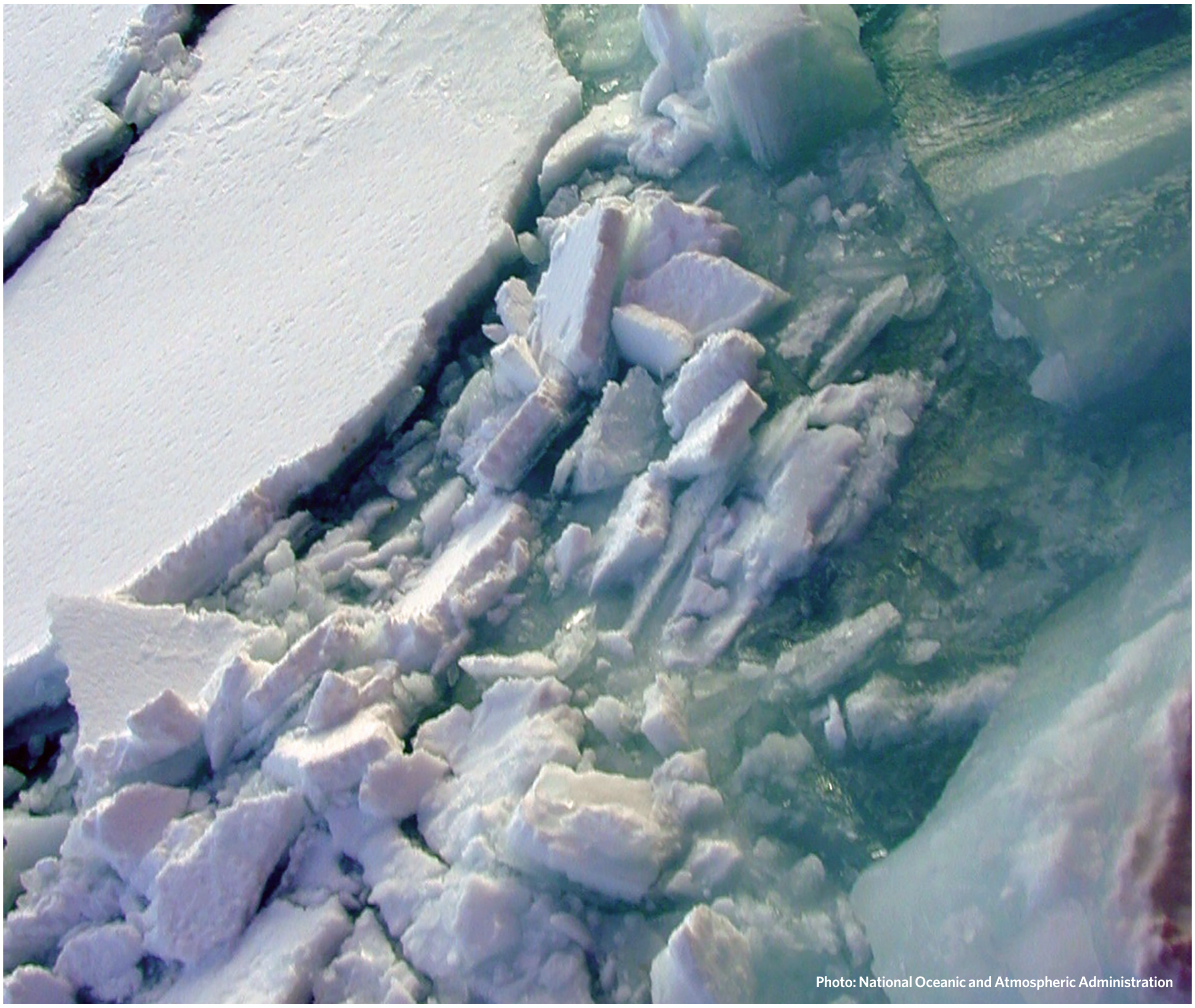
With traditional sources of oil and gas decreasing, industry has been expanding its efforts into frontier areas, including the U.S. Arctic Ocean



Areas available for leasing consideration in the 2012-2017 OCS leasing program

Active federal leases

Source: U.S. Bureau of Ocean Energy Management



Ice floes scatter in the wake of the U.S. Coast Guard ice breaker Healy during summer scientific studies in Alaska's Chukchi Sea.

Arctic oil spill prevention recommendations summary

One goal of Arctic OCS standards is to prevent oil spills. At stake are not only the safety of crew members and rescue workers, but also a rich and complex ecosystem found nowhere else in the United States.

Our recommendations call for improved oil spill prevention requirements that match the Arctic's unique engineering and operating challenges. Arctic OCS standards would provide consistent guidelines on how to explore for, design, build, install, and operate equipment to safely develop oil and gas resources using best Arctic science, technology, and practices. Pew's recommendations include:

- Arctic seasonal drilling limits.
- Arctic drilling design and operation standards.
- Arctic facilities design and operation.
- Arctic vessel and logistical support.
- Pollution prevention operating standards.

Arctic seasonal drilling limits

Arctic offshore drilling operations into hydrocarbon-bearing zones should be limited to periods when the drilling rig and its associated system for responding to an oil spill are capable of working and cleaning up a spill in Arctic conditions. This period should include the time required to control a blowout by drilling a relief well to intercept the well involved in the blowout and bring it under control. Seasonal drilling limits ensure that drilling through hydrocarbon zones, where there is a risk of a well blowout spilling oil into the ocean, does not occur when operations to recover spilled oil are impossible or substantially less efficient at removing the oil (see box).

Open water in the Arctic OCS of the United States generally extends from early July through the second week of October, or about 106 days. If a well blowout occurs, it may take about 60 days to complete a relief well on average. This means drilling in the Arctic OCS should be limited to approximately 46 days during a 106-day open-water season because oil spill response techniques are more successful during summer. Oil spill response techniques are substantially less efficient during periods of broken ice, periods of fall ice freeze-up, and when oil is trapped under ice. (See Figure 5.)

In the nearshore area of the Beaufort Sea OCS, it may be possible to drill an exploration well during the landfast winter ice period. In this case, drilling through hydrocarbon zones should occur only when solid ice has formed, serving as a solid platform for drilling operations, and stopping with adequate time to drill a relief well and clean up any spilled oil before spring ice breakup.

Figure 5[31]

Arctic Seasonal Drilling Limits

Icy conditions reduce the efficacy of oil spill response most of the year

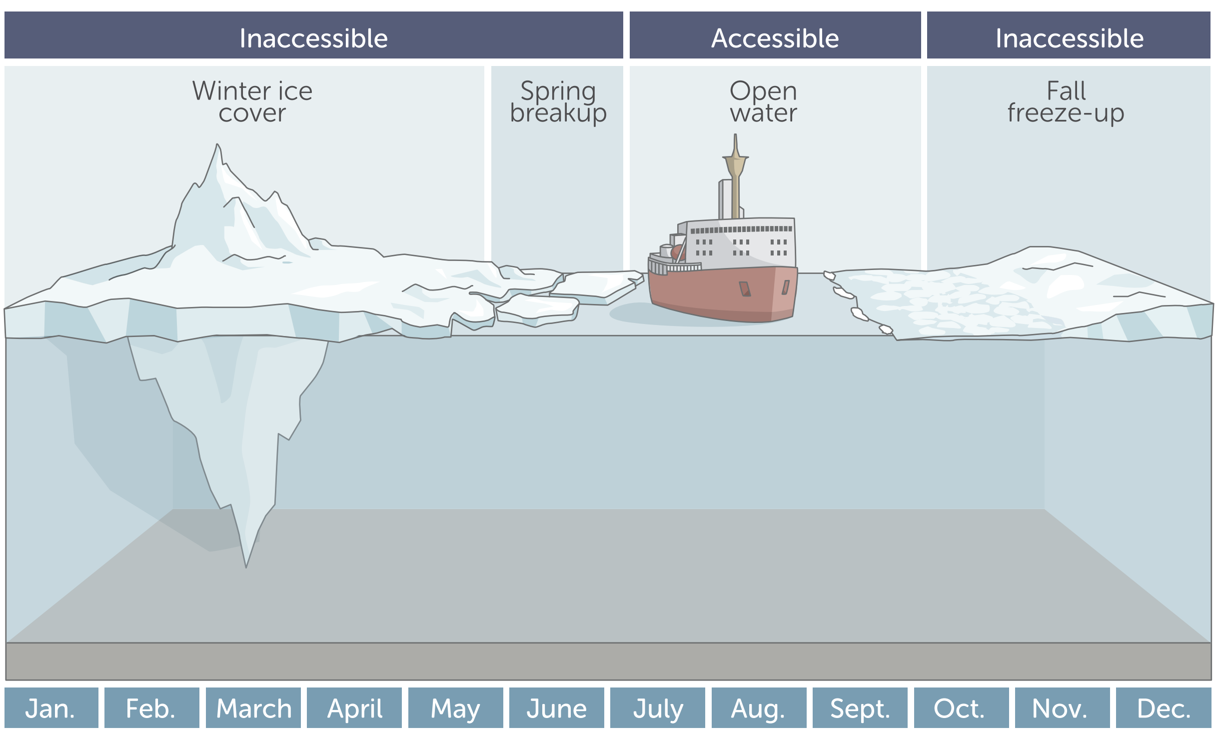


Table 2[32]

Seasonal Constraints to Cleaning Up an Arctic Oil Spill

The symbols show the approximate operating limits for mechanical oil removal and burning of spilled oil under various concentrations of ice and weather conditions

Limiting Factor	Ice Coverage						Wind			Wave Height			Visibility		
Conditions	Oil spilled on top of ice or among ice					Oil spilled under solid ice									
	<10%	11%-30%	31%-70%	>70%	Solid ice 100%		0-20 mph	21-35 mph	>35 mph	<3 ft.	3-6 ft.	>6 ft.	High	Mod-erate*	Low†
Mechanical recovery with no ice management	○	✕	✕	✕	✓	✕	✓	○	✕	✓	○	✕	✓	○	✕
Mechanical recovery with ice management	✓	○	✕	✕	✓	✕	✓	○	✕	✓	○	✕	✓	○	✕
In-situ burning	✓	○	✕	○	✓	✕	✓	✕	✕	✓	○	✕	✓	○	✕

✓ Favorable response conditions ○ Response hindered ✕ Response ineffective

* Moderate visibility is light fog or visibility of less than a mile. † Low visibility is heavy fog, less than a quarter mile of visibility, or darkness.

Source: Nuka Research and Planning Group

Currently, Interior Department regulations do not specifically include Arctic seasonal drilling limits. Table 2 shows the approximate operating limits for mechanical oil removal and burning of spilled oil under various concentrations of ice and weather conditions.

Seasonal drilling limits have not been consistently applied to Arctic drilling programs because of the lack of a federal regulatory standard. The Interior Department, for example, effectively applied seasonal drilling limits to Shell's 2012 Chukchi Sea OCS drilling project, yet Interior did not apply seasonal drilling limits to Shell's 2012 project in the Beaufort Sea even though ice sets in earlier in the Beaufort Sea and is of the thicker, stronger and therefore more dangerous multiyear ice.[33]

Pew's recommendations:

- Arctic offshore drilling operations into hydrocarbon-bearing zones should be limited to periods when the drilling rig and its associated system for responding to an oil spill are capable of working and cleaning up a spill in Arctic conditions. This period should include the time required to control a well blowout by drilling a relief well to intercept the well involved in the blowout and bring it under control.
- In the nearshore area of the Beaufort Sea OCS, it may be possible to drill an exploration well during the landfast winter ice period. In this case, drilling through hydrocarbon zones should occur only when solid ice has formed, serving as a solid platform for drilling operations, and stopping with adequate time to drill a relief well and clean up any spilled oil before spring ice breakup.

The presence of ice hindered cleanup efforts when the Icelandic containership Godafoss ran aground and started leaking heavy oil in the Ytre Hvaler Marine National Park in southern Norway in February 2011.

See Appendix I for additional recommendations on Arctic seasonal drilling limits.

Arctic drilling design and operation standards

The design of the drilling rig, the blowout preventer, or BOP, and cementing practices are all essential to safe drilling operations and accident prevention. Drilling rigs must be designed and operated to meet the Arctic conditions they will encounter. Due to the remote nature of Arctic drilling operations, rigs must be self-sufficient and carry a minimum level of well control materials such as drilling mud, cement, and extra fuel.

Nearshore areas of the Chukchi and Beaufort seas have landfast ice. By the end of winter, landfast ice is typically 5 to 7 feet thick, extending seaward to a depth of about 60 feet.[34] In the nearshore shallow waters of the Beaufort Sea, there are two potential exploration drilling seasons. The first is during open water in summer. The second is during landfast ice conditions in winter. Historically, ice-resistant, bottom-founded (fixed to the seafloor) drilling systems have been used in nearshore areas during the summer, or ice- or gravel-reinforced islands were constructed with drilling units on top of them for winter drilling.

In the deeper waters of the Beaufort and Chukchi seas, exploration drilling occurs during open water in summer, using floating drilling rigs. Here, the ice is moving throughout most of the year and the amount of thick multiyear ice increases with increasing distance from shore.[35] Therefore, drilling rigs must be equipped to encounter thick multiyear ice floes, even during summer drilling seasons.

Performance standards for Arctic OCS drilling rigs

Drilling rig selection is a critical step for Arctic oil and gas exploration and for delineation well drilling—drilling wells to define the size of the oil reservoir. Operators must select a drilling rig that is suitable to operate in the conditions the rig may encounter while drilling the planned well and be able to provide relief well drilling assistance to other rigs working in the Arctic to control a well blowout.

The biggest concern is a late-season well blowout that requires drilling to continue into late fall-early winter ice, which would require a Polar Class rig. Constantly moving a rig off the drilling site to avoid ice will not be an option when a blowout occurs, and a relief well drilling rig must remain in position to drill a relief well in the weather and ice conditions that may be present during the late fall and early winter. These kinds of drilling operations would require a Polar Class rig. (See Table 3.)

Mobile Offshore Drilling Units, or MODUs, are floating rigs or "drillships" used for Arctic exploration drilling. MODUs are given a Polar Class rating based on hull strength and ability to operate in ice. MODUs working in Arctic waters, even in summer, require icebreaker support for ice management and must be capable of transiting thick first-year Arctic ice, with the potential to encounter thicker and harder multiyear ice. Arctic drillship design must include a hull shape that:

- Minimizes ice loads, or the weight and stress of ice against a vessel.
- Prevents ice accumulation in the "moon pool" area (where drilling equipment passes through, typically located in the center of the MODU).
- Prevents ice damage to propulsion systems.
- Safely transits ice-infested waters.

The International Association of Classification Societies[37] classifies equipment using the term Polar Class to describe the type of ships constructed of steel, intended for navigation in ice-infested waters, and with respect to operational capability and strength.

The International Maritime Organization, or IMO, "Guidelines for Ships Operating in Polar Waters"[38] also uses the term Polar Class vessels to address the additional risk imposed on vessels by the harsh environmental and climatic conditions in polar waters. The IMO 2010 Guidelines states that "only ships with a Polar Class designation or comparable alternative standard of ice-strengthening appropriate to the anticipated ice conditions should operate in polar ice-covered waters."

Polar Class designations range from Polar Class 1, the strongest vessel that is capable of year-round operation in all polar waters in thick ice, to Polar Class 7, the lowest-strength vessel capable of operating in summer and autumn's new, thinner ice. These ratings are applied to all types of vessels operating in polar waters, not just MODUs.

As shown in Table 3, MODUs operating in summer and autumn with first-year ice should meet at least a Polar Class 7 standard. MODUs operating later in the year must meet a higher Polar Class standard.

Once exploration and any further drilling required to delineate the hydrocarbon formation is complete, a year-round OCS production facility may be installed. A development drilling rig would likely be installed on top of the year-round OCS production facility to drill the remaining production wells. (See Page 20 for Arctic OCS production facility design standards.) The development drilling rig would need to be capable of withstanding the Arctic weather conditions in which it plans to operate, meaning that like the production facility, it must be enclosed and winterized to withstand year-round weather.

Pew's recommendations:

- Arctic OCS oil and gas operators should be required to use purpose-built Polar Class drilling rigs.
- The rig should hold a valid certification from a recognized classification society throughout the operation that verifies the drilling rig is appropriate for the site, intended use, and season of operation.
- An independent third-party expert should be required to inspect the rig and certify that it meets the qualifications for the Arctic conditions it may encounter.

Arctic OCS BOP standards

The offshore well blowouts in the East Timor Sea off Australia in 2009 and in the Gulf of Mexico in 2010 are reminders of the critical importance of high-quality, properly operating blowout preventer, or BOP, systems and the need for redundant backup systems. Blowout preventers are critical well control devices, which means their age and condition are key factors in performance and reliability. There is no age limit on BOP systems in Interior Department regulations, meaning these systems operating in the Arctic could be several decades old.

Pew's recommendations:

- Arctic BOP systems should be inspected and verified by an independent third-party expert prior to initial use and after major repairs, and be recertified at least every five years.
- Redundant BOP systems should be installed to ensure the BOP functions in an emergency. This includes backup BOP systems on-site; double-blind shear rams in each BOP to close in the well; multiple access points to control the BOP in case one access point is blocked or does not function; and a means to remotely operate the BOP if a well control incident impedes direct access to the BOP.

Table 3[36]

Polar Class

Ratings for vessels operating in ice

Polar Class	Ice Description
Polar Class 1	Year-round operation in all polar waters
Polar Class 2	Year-round operation in moderate multiyear ice (more than 3 meters thick) conditions
Polar Class 3	Year-round operation in second-year ice (2.5 meters or more) that may include multiyear ice inclusions
Polar Class 4	Year-round operation in thick first-year ice (more than 120 centimeters thick) that may include old ice inclusions
Polar Class 5	Year-round operation in medium first-year ice (70 to 120 centimeters thick) that may include old ice inclusions
Polar Class 6	Summer/autumn operation in medium first-year ice (70 to 120 centimeters thick) that may include old ice inclusions
Polar Class 7	Summer/autumn operation in thin first-year ice (30 to 70 centimeters thick) that may include old ice inclusions (3 or more meters thick)

Source: International Association of Classification Societies

Arctic well cementing practices

Cement is a critical structural component of a well. Cement secures the drill pipe and provides a barrier for hydrocarbons to prevent a blowout. Oil and gas leaks can occur due to poor cementing practices, such as installing poor-quality cement, contaminating the cement with drilling mud, installing cement incorrectly, or damaging the cement while working on the well. Several of these cement integrity deficiencies contributed to the Deepwater Horizon blowout.

In the Arctic, cold soil compromises cement strength, which means specialty cements are required to ensure a strong, durable barrier. Conventional cements used in temperate locations are not satisfactory in Arctic wells because they freeze before they can set up sufficient compressive strength. Thawing of frozen soils must also be prevented. Thawing can increase the volume of cement needed, cause the well to subside, and create stress on the well piping.

Methane gas hydrates are commonly encountered when drilling Arctic wells. Methane gas hydrates are essentially crystals of methane gas trapped in ice and typically found relatively shallow, hundreds of feet deep. Methane gas hydrates become unstable, changing from a solid to liquid and gas as temperature and pressure changes occur during the cementing process. The intrusion of methane gas hydrates into cement can weaken the cement, creating spaces that allow hydrocarbons to pass through the cement, potentially resulting in well control incidents if not considered in the well design.

Electronic tools can be lowered into the wellbore to examine the cement quality. The Interior Department does not currently require these cement evaluation tools to be run on each Arctic well.

Photo: Jose Mandojana

A blowout preventer, or BOP, system—shown here—is designed to seal off a runaway well. A well-designed, properly operating BOP is essential to safe drilling operations and accident prevention.

Pew's recommendations:

- Arctic-specific cementing standards should account for permafrost and methane gas hydrates.
- A cement evaluation tool, cement bond log, or equivalent logging tool should be used to verify successful cement placement in all Arctic OCS wells.

(See Appendix I for additional recommendations on Arctic well cementing, minimum level of well control materials, Arctic OCS BOP standards, and Arctic OCS drilling rig performance standards.)

Arctic facilities design and operation

Once exploration drilling is complete and sufficient oil and/or gas resources are found to support year-round production, a more permanent offshore production facility may be installed with a pipeline connecting it to shore. Offshore production facilities typically include development drilling operations, wellheads, processing facilities, storage, and living quarters.

The offshore production facility and offshore pipeline will likely operate year-round. This means these facilities must be designed to account for strong ice forces and other Arctic hazards. Arctic OCS equipment should be designed in accordance with Arctic engineering practices, and operating standards should be based on worst-case historic weather conditions.

Arctic OCS production facility and transportation performance standards

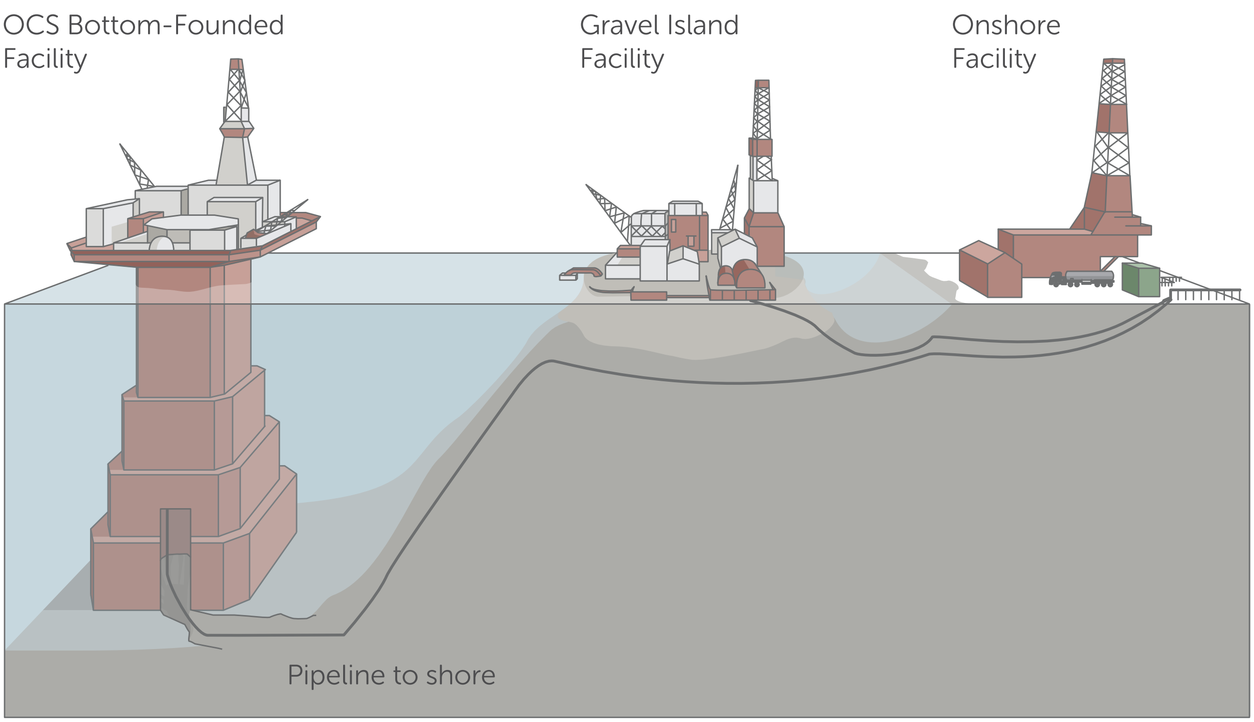
Frozen for eight to nine months of the year, the Arctic Ocean features ice that varies in thickness, age, and strength. Facilities must be designed for new first-year ice vthat can be 5 to 7 feet thick;[39] multiyear ice floes that can be miles wide and miles long and can consist of ice that is 10 feet to 100 feet thick; and icebergs.

Six large multiyear ice floes in the Chukchi Sea have occurred since 2000, with the largest floe estimated to be 300 feet wide and 12 miles long with a 90 percent ice concentration.[40] In February 2012, two large pieces of ice

Figure 6[44]

Arctic OCS Bottom-Founded Oil and Gas Production Facility Design

If OCS development moves forward, production facilities will need to be engineered to withstand strong, year-round ice forces



were discovered off the Chukchi Sea coast. The larger one was estimated to be 260 feet long, 131 feet wide, and 66 feet above sea level.

In 1992, a massive ice floe in the U.S. Beaufort Sea measured several miles in width and length and was so thick that it grounded out (hit the seafloor) even in water depths of 105 feet.[41]

Facilities designed to withstand ice in the Beaufort and Chukchi seas need to be 10 to 20 times stronger than the large, temperate-water Gulf of Mexico platforms built for hurricanes and rough seas, or subarctic platforms used in south-central Alaska's Cook Inlet and built to withstand ice and storm events.[42] Offshore facilities designed for the temperate waters of the Gulf of Mexico or subarctic waters of Cook Inlet are not suitable for use in the Arctic.

Bottom-founded structures or gravel islands, connected to shore by pipelines buried below the ice gouge and scour depth, have been proved to be the safest current design for Arctic offshore operations. In 2008, the Interior Department funded a study of Arctic design concepts for both exploration and production facilities and drilling rigs in the Beaufort and Chukchi seas.[43] Interior's Arctic Offshore Technology Assessment concluded that bottom-founded platforms are safe and economical for the Arctic in water up to about 250 feet deep and gravel islands to about 60 feet deep, and that alternative designs in deeper waters will need to be developed. Other facility designs examined could not withstand the formidable crushing ice forces that are present year-round. (See Figure 6.)

Pew's recommendations:

- All Arctic offshore production facilities should use a bottom-founded design or be built on a gravel island if water depth allows for it. These facilities should be built and installed according to Arctic engineering practices and be able to withstand the worst-case geological hazards, Arctic temperatures, and wind, wave, and ice hazards that may be encountered.
- Offshore pipelines should be the required oil transportation method to move oil safely from the offshore facility to market. No tanker transportation of crude oil should be allowed during development due to the high risk of tanker transit in ice conditions resulting in ice damage to the hull, a collision, or grounding.
- These limitations should be met unless another alternative is proved environmentally preferable and safer.

Arctic OCS pipeline performance standards

Arctic OCS pipelines must be buried at a sufficient depth to avoid damage. Pipeline damage may occur from ice gouging by icebergs and ice-pressure ridging (two floes of ice coming together) and strudel scour (whirlpools that wash away the seabed). Pipelines buried in frozen soil (permafrost) must also be designed to minimize heat transfer to soil that can cause the frozen soil to melt and the pipeline to be subjected to bending stresses as it sags. (See Figure 7.)

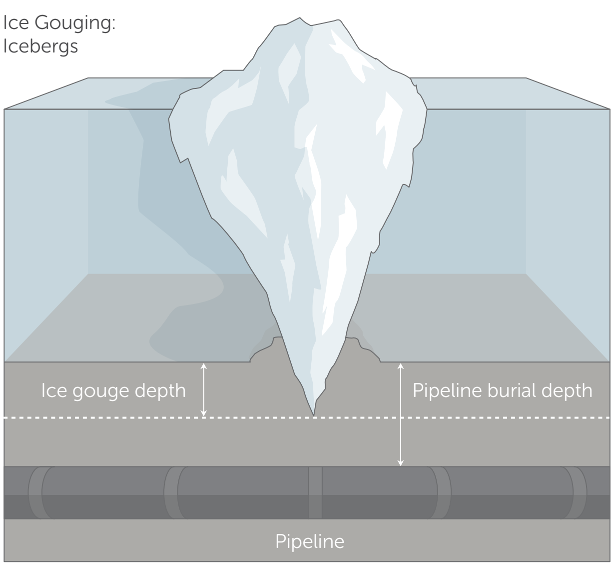
Arctic OCS pipelines may operate year-round, buried below the seabed. Response to an oil spill could be delayed up to six months for a pipeline leak under solid or broken ice. Because buried subsea Arctic pipelines are inaccessible for external monitoring, maintenance, and repair, they require a stronger design and additional oil spill prevention systems to be included in the initial installation. The installation of a tank and pump system provides a means of emptying the pipeline to control a spill, especially during periods when spill response is not possible.

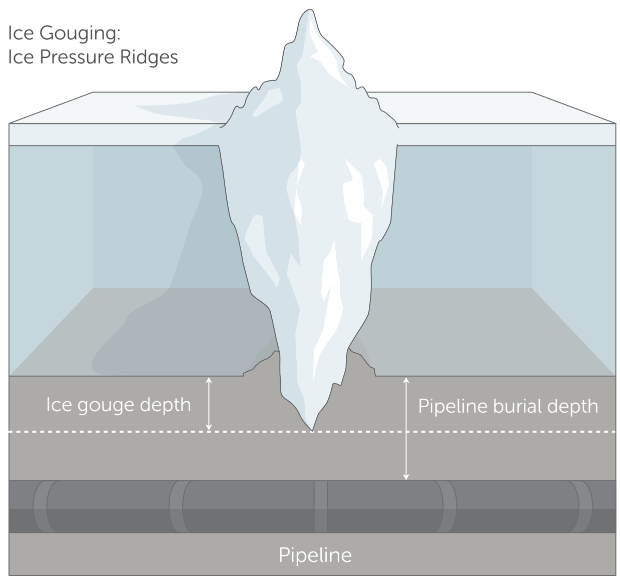
Figure 7[45]

Arctic Hazards for Oil Pipelines

Icebergs and pressure ridges

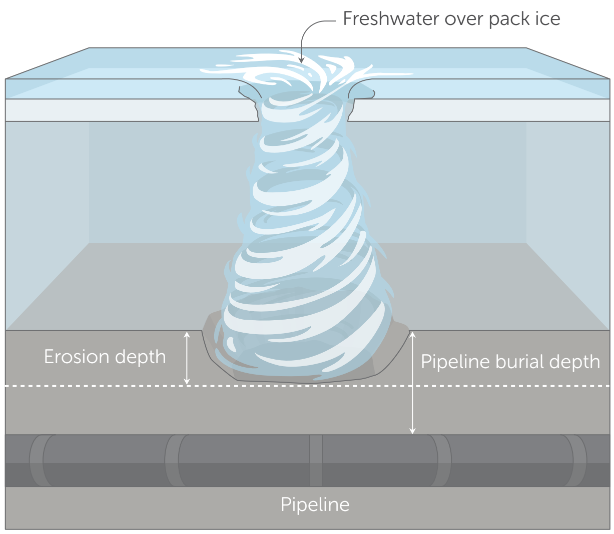
Icebergs that drift into shallower water may drag along the seafloor, gouging it along the way. When two floes of pack ice collide, a pressure ridge may form with ice rubble building above and below the surface. Ice below the water's surface may dig into the seafloor and damage the pipeline if it is not buried deep enough.





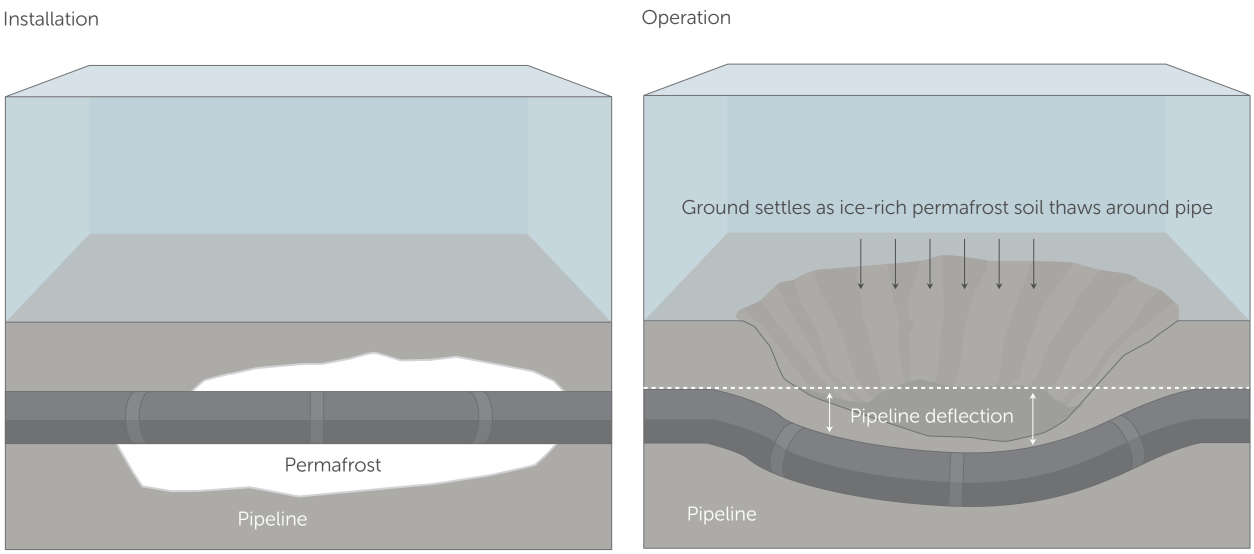
Strudel scour

Strudel is the German word for "whirlpool." Strudel scour describes an event in which, during spring melt, a large volume of freshwater flows onto pack ice and drains through a hole or crack in the ice creating a severe whirlpool down to the seabed, where the water pressure can wash layers of the seabed away, creating a hole more than 12 feet deep.



Permafrost thaw

Depending on the pipeline's proximity to the permafrost layer, thawing of the permafrost could cause the seafloor to settle, creating a depression and putting strain on the pipeline.



Pew's recommendations:

- Pipelines should be buried below the depths of seabed ice gouging and ice strudel, and be designed to minimize settling due to permafrost thaw.
- Pipelines should be constructed using double-walled pipe or multiple pipelines and should be contained inside one larger pipe (a utilidor or pipe-in-pipe system) to provide a redundant pipe wall for secondary containment of oil in case of a leak. No single-walled pipelines should be allowed.
- Two leak-detection systems should be installed on the pipeline to provide redundant leak-monitoring capability.
- Tank and pump systems should be installed capable of completely evacuating the pipeline either to an offshore facility or to an onshore storage location in the event a leak is identified.
- Pipelines should be designed and operated to prevent corrosion and be equipped with access points for launching and receiving corrosion-detection equipment (commonly called "smart pigs") and pipeline maintenance equipment (commonly called "pipeline pigs").
- Pipelines should have a robust inspection, monitoring, repair, and replacement program.

Arctic OCS tank performance standards

Crude oil and fuel storage tanks used in the Arctic OCS pose a spill risk. Fuel tanks store fuel to be used in combustion equipment. Offshore crude oil tanks may be used to store oil before sending it to shore in a subsea pipeline or for evacuating and storing oil from a leaking pipeline.

The best strategy is to build robust tank systems with accurate leak-detection systems and a means to evacuate oil from the tank if a leak is detected.

Pew's recommendations:

- Arctic tanks should be built of double-wall and double-bottom construction and be designed and operated to prevent corrosion.
- Arctic tanks should have a robust inspection, monitoring, and repair program.
- Arctic tanks should have a leak-detection system installed between the double-bottom that is equipped with automated visual and sound alarms and automated overflow alarms.
- Arctic tanks should be connected by piping to one or more additional tanks that are able to hold the leaking contents in the event of a leak.

(See Appendix I for additional detail on Arctic OCS equipment design and operating standards based on worst-case historic conditions, Arctic OCS pipeline performance standards, Arctic OCS production facility and transportation performance standards, and Arctic tank performance standards.)

Arctic vessel and logistical support

Fuel transportation, supply, and oil spill response vessels and tugs that are part of Arctic OCS exploration, development, or production operations must be designed with vessel hulls and specialized systems to function safely in ice and extreme cold.

The Interior Department currently requires that oil and gas operators submit Critical Operations Curtailment Procedures, or COCPs, that identify ice conditions, weather, and other constraints on operations, as well as the procedures to curtail or shut down those operations.[46] This regulation assumes that it will be safe to cease activity if a vessel's capability is exceeded by ice or weather conditions or that it is in the best interest of human health or the environment that the activity ceases.

There are, however, a number of Arctic vessel and logistical support functions that may require a vessel to continue to operate in severe ice or harsh weather to respond to operational, logistical, health, safety, and environmental issues. Arctic vessels may be called upon to rescue personnel, conduct spill response operations

Photo: U.S. Coast Guard

A Shell Oil drilling rig, the Kulluk, ran aground in late 2012 after towlines broke and the vessel towing it suffered multiple engine failures.

in ice-infested waters, tow a drilling rig or another support vessel, provide support for a relief well rig, or tow emergency equipment such as well capping and containment systems or provide firefighting equipment.

The Interior Department's "Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program" identified several significant vessel and logistical support problems, including insufficient vessel towing capability and vessel logistical planning. As a result, Interior recommended that future Arctic plans include a "comprehensive and integrated operational plan" with schedules for mobilization and demobilization of operations.[47]

Vessels operating in the Arctic must have thicker, reinforced hulls and propulsion systems that are protected from damage by ice.[48] The vessel's deck and equipment on it must be winterized to prevent freezing and malfunction and must include heating and ventilation systems that have anti-icing and deicing equipment. Additional enclosed areas for personnel and equipment are essential, as are heated ballast and water tanks, helidecks, and exposed walkways.[49]

The remote location of Arctic OCS drilling sites and their distance from additional oil spill response support require oil and gas operators to plan and prepare for self-rescue and emergency response.

Recognizing the need to plan for every phase of an Arctic offshore operation, Pew recommends that any Interior Department approval of drilling rigs that must be towed (rather than being self-propelled) should be accompanied by towing plans to have the drilling rig safely docked before hazardous winter conditions set in and that towing plans describe how an operator would respond to a failed towing attempt.

The Interior Department, in coordination with the U.S. Coast Guard, should incorporate Arctic OCS vessel performance standards into federal regulations to ensure that these vessels are capable of providing support in Arctic conditions and during the seasons that the operator plans to conduct activities, including the time to mobilize equipment to the site, demobilize equipment, and provide emergency services.

Pew's recommendations:

- Vessels should meet the IMO's Guidelines for Ships Operating in Polar Waters.[50]
- All fuels should be transported in double-hulled vessels with sufficient tug assistance to avert a potential collision or grounding.
- Vessels should be inspected by a third-party expert from a technical classification society or a licensed professional engineering inspection or certification firm to ensure vessels are in good condition and suitable for operation in the Arctic. The inspector should consider the vessel's fitness for planned operations and for unplanned operations that may require it to remain at the drill site past the approved drilling season.
- The operating season should end with sufficient lead time to ensure that all drilling rigs and other equipment can be safely towed and docked for the winter.
- A drilling rig towing plan should demonstrate that the operator can safely transport the drilling rig in the maximum weather conditions that may be encountered; include at least one tug capable of towing the rig in worst-case conditions, with a plan for immediate tug assistance; describe procedures for recovering a rig that breaks free of the towing vessel; define weather and other conditions where it is unsafe to tow the drilling rig; and identify safe harbors where the rig will be placed during these periods.
- Vessels transiting the Arctic should have state-licensed marine pilots aboard.

The oil rig Kulluk broke loose of its towlines near the Coast Guard base on southwest Alaska's Kodiak Island. The vessel support it received would not be readily available in the Arctic.

(See Appendix I for additional detail on Arctic OCS vessel performance standards.)

Arctic pollution prevention operating standards

The Arctic is undergoing rapid change, warming at twice the rate of the rest of the planet,[51] and threatening ecosystems supported by the presence and proximity to sea ice. Warming temperatures and diminishing sea ice threaten not only the ice-associated marine life but also the food security of Arctic indigenous peoples. For many residents of the Arctic, there is a direct connection between the health of the marine environment and the health of their food supply and culture.

In the next several years, the U.S. Arctic Ocean will almost certainly face an expansion of industrial activity. Exploration drilling for hydrocarbons in the Beaufort and Chukchi seas, and potential development of those hydrocarbons, may introduce additional air, water, and noise pollution and other unmitigated impacts into an already stressed ecosystem. Arctic pollution can be mitigated by:

- Preventing oil spills when oil spill response is not possible.
- Ensuring that operators have experience and expertise working in Arctic conditions.
- Installing air pollution controls.
- Committing to zero discharge by collecting and properly disposing of waste at approved facilities rather than discharging it into the ocean.

Arctic OCS Critical Operations Curtailment Procedures

Critical Operations Curtailment Procedures, or COCPs, provide information on the general steps that operators will take to reduce or shut down oil and gas operations during harsh weather, such as high winds or encroaching ice. Interior Department regulations currently give broad discretion to the operator to determine when to shut down operations and do not require operators to consider the feasibility of responding to an oil spill in the decision to curtail or shut down operations.

COCPs are successfully used by oil and gas operators in the Gulf of Mexico and the Arctic to curtail or shut down offshore operations due to high winds and storms associated with hurricanes or severe weather and to move Arctic exploration drilling rigs in the presence of significant ice. However, in the Arctic, exploration and production operations are not required to curtail or shut down operations during periods when wind, waves, and sea ice conditions make oil spill response impossible. Yet, weather conditions have a dramatic effect on the tools and tactics available when responding to an oil spill and conducting cleanup operations, determining what types of oil recovery methods and equipment can be used and their effectiveness. (See Tables 1 and 2.)

After the 1989 Exxon Valdez oil spill, the federal government required tanker operators transiting Alaska's Prince William Sound to identify weather conditions that would increase the risk of an oil spill and to curtail operations during those conditions. Today, oil tanker transits and loadings in Alaska's waters are limited to certain wind, wave, and sea conditions to prevent an oil spill from occurring when spill response operations are not possible.

Pew's recommendations:

- COCPs should establish specific, quantitative, measurable performance standards and thresholds for when Arctic exploration or production operations should cease due to weather or logistical impediments or when responding to an oil spill is not possible.

- A site-specific statistical assessment should be completed to examine personnel and equipment limits for all Arctic exploration, development, and production operations, including drilling rigs, production equipment, vessels, support systems, and oil spill response equipment and determine when the limiting thresholds are reached.
- A monitoring program (similar to the ice-monitoring procedures in use for the COCPs) should be instituted to monitor temperature, visibility, wind, and wave height on an hourly basis, and forecast those conditions at least 48 hours out to determine when thresholds are or will be reached and when prevention measures should be instituted.

Arctic OCS exploration and production expertise, experience, capacity, competencies, and qualifications

The Arctic Ocean's severe climate and operating conditions require thoughtful planning and experience operating in this environment. Arctic drilling, well control, and facility design and operation require additional, specialized expertise and experience. The Interior Department, however, does not require oil and gas operators to demonstrate they have this specialized expertise, experience, or capacity before exploration, development, and production plans are approved.

There is ample reason for concern. In the Interior Department's 60-day review of the 2012 Arctic offshore exploration season, there were reports of contractors without Arctic experience and use of equipment not suited for the Arctic. For example, some helicopters lacked critical deicing equipment, pilots unable to fly under the Federal Aviation Administration's Instrument Flight Rules delayed the transition of workers to and from the drilling rigs and onshore facilities, and some drilling contractors lacked experience drilling mud-line cellars. (Mud-line cellars are a required and basic operation for offshore Arctic drilling that protects the BOP from ice hazards such as ice gouging).[52]

By comparison, Greenland requires operators to undergo an operator prequalification program to demonstrate they have the expertise, experience, and capacity to "undertake drilling activities offshore in harsh remote Arctic locations" prior to leasing.[53] And, Norway and Greenland both require the operator to provide extensive information on personnel competencies and qualifications.[54]

Pew's recommendations:

- Interior should establish Arctic OCS exploration and production expertise, and experience, capacity, competency, and qualification standards.
- Interior should require oil and gas drilling operators to demonstrate their Arctic exploration and production expertise, experience, and capacity in their Exploration Plan or Development and Production Plan, prior to approval.

Arctic air pollution prevention controls

In December 2011, Congress transferred authority to regulate air pollution resulting from Arctic offshore oil and gas exploration, development, and production activities from the U.S. Environmental Protection Agency to the Interior Department. The department's air pollution control regulations are not as stringent as EPA's for sources of similar size and type of air pollution. For example, under Interior's regulations, many offshore oil and gas facilities are exempt from air-quality standards and are not required to install pollution controls. Interior Department air pollution regulations were developed in the 1980s and do not include some of the important improvements made in the conduct of air pollution impact assessments and air pollution controls that EPA has adopted in the three decades since.

Pew's recommendations:

- Interior should ensure that its air pollution impact assessment and control technology requirements are at least as stringent as those followed by EPA.
- Interior should require each OCS exploration, development, and production plan to account for the collective emissions of drilling equipment, production facilities, and support vessels.
- Interior should require modern technological controls to limit significant sources of pollutions.

Arctic pollution prevention: Zero discharge of drilling muds, drill cuttings, produced water, and sanitary and other industrial wastes

Oil and gas drilling operators have proved it is technically feasible to collect and safely dispose of drilling muds, drill cuttings, produced water (water produced in association with hydrocarbons), and sanitary waste without discharging it into the ocean. Proper handling and disposal of these waste products is important to environmental protection because muds and cuttings can be contaminated with metals and other chemicals that accumulate and persist in the environment. Produced water is typically contaminated with some residual oil, and traditional knowledge confirms that sanitary waste can deflect migrating marine mammals farther offshore. Discharge of all other industrial waste streams should be prohibited where technically feasible methods of waste collection and disposal exist.

The Arctic Council—an intergovernmental forum made up of eight member states and Arctic indigenous participants—in April 2009 published "Arctic Offshore Oil and Gas Guidelines," which supports enhanced pollution prevention requirements in the region, including the prevention of waste discharge when technically feasible waste-management alternatives exist, and the implementation of waste reduction, reuse, and recycling strategies, and selection of environmentally friendly "green" chemicals.[55]

Pew's recommendations:

- Interior should revise current pollution prevention regulations to prohibit the discharge of drilling muds, drill cuttings, produced water, and sanitary waste into the Chukchi and Beaufort seas. All other discharges, where technically feasible methods of collection exist, should also be prohibited.
- Interior should require oil and gas drilling operators to provide supporting toxicological data demonstrating that they have selected chemicals with the lowest ecological impact for discharges where it is not technically feasible to collect the waste.

(See Appendix II for additional recommendations on Arctic OCS COCPs; Arctic OCS exploration and production expertise, experience, capacity, competencies, and qualifications; air control pollution prevention; and zero discharge of drilling muds, drill cuttings, produced water, and sanitary and other industrial wastes.)

U.S. Coast Guard icebreaker cutter Healy, followed by the Canadian Coast Guard ship Louis S. St-Laurent, cuts through September sea ice in the U.S. Arctic Ocean

Arctic oil spill response recommendations summary

Drilling for oil is a dangerous enterprise even in temperate climates, as evidenced by the Deepwater Horizon disaster in the Gulf of Mexico. The Arctic's severe conditions and changeable weather increase the likelihood of an accident. For these reasons, strong Arctic OCS standards are needed to minimize oil spill potential and maximize the ability to clean one up.

Arctic OCS standards for oil spill response should take into account the Arctic's remote location, lack of infrastructure, and challenging operating conditions due to the harsh and changing climate, and should include realistic planning for a worst-case spill. Pew's recommendations include:

- Arctic standards for oil spill response planning.
- Arctic well blowout source control.
- Arctic oil spill response equipment and personnel.
- Arctic equipment testing and verification.
- Public participation and transparency.

Arctic standards for oil spill response planning

Adequate equipment and trained personnel must be on location to remove a worst-case oil spill in the Arctic. Oil spill response resources should be located near potential oil spill sources to avoid delays due to logistical and weather impediments. Advanced Arctic oil spill response planning will be key to the success of the response effort and should include: a worst-case case oil discharge estimate; an assessment of where the oil may be expected to travel; the amount and type of equipment needed to remove the spill; and oil-removal benchmarks to guide the response effort.

Arctic oil spill trajectory analyses and mapping standards

The Interior Department requires OCS operators to prepare Oil Spill Response Plans that include a worst-case oil discharge scenario with an oil spill trajectory analysis estimating the maximum distance that oil could travel from the spill source while it persists in the environment and the offshore and coastal areas that could be affected.[56] However, Interior regulations do not currently require operators to examine the variety of oil spill trajectories that could occur under a range of potential Arctic weather conditions, including adverse weather.

Trajectory models used for oil spills in temperate waters are inadequate for modeling oil in ice because they require detailed wind and current data that are not available for many areas of the Arctic,[57] and they do not include the trajectory interference caused by ice that can divert oil or cause oil to be trapped in or under the ice. The capability to predict ice dynamics at a scale useful for trajectory models is limited.[58] While a joint oil and gas industry project is working to improve trajectory models used for oil spills in ice-infested waters,[59] there has been little advancement in this area.

Realistic oil spill trajectory estimates will allow more accurate identification of Arctic offshore and coastal areas that could be affected, and ensure that plans are put in place to protect these areas in the event of a spill. The Interior Department approved trajectories for offshore exploration in the Beaufort and Chukchi seas in 2012, and those trajectories assume that the oil spill can be cleaned up at rates that have not been demonstrated in Arctic conditions. These trajectories are insufficient for both short- and long-term oil spill response planning.

The Interior Department's regulations should be revised to more specifically require oil spill trajectories that examine the path of unrecovered oil for at least one year after the spill, over a wide range of weather conditions and recovery rates to assist planners in determining how many spill removal task forces are needed, where to pre-stage response equipment, and which sensitive areas may be at risk.

Pew's recommendations:

- Oil spill trajectories should reflect the maximum distance that oil can be expected to travel under various oil removal scenarios, including no response; 1 to 5 percent oil removal (based on low recovery rates in icy conditions); and 10 to 20 percent oil removal (best-case recovery rates in temperate water).
- Oil spill trajectories should examine a realistic range of potential Arctic weather conditions, including adverse weather scenarios based on at least 10 years of data, preferably 20 years.
- Oil spill trajectories should include an overwintering spill trajectory scenario to show where the unrecovered oil would travel when oil spill response is not possible.
- Oil spill trajectories should use a spill trajectory computer model approved by the National Oceanic and Atmospheric Administration capable of modeling subsurface and surface oil movement in ice-infested waters.

Arctic oil spill recovery calculations and minimum equipment requirements

Oil and gas operators are required to calculate the amount of equipment needed to respond to an oil spill for 30 days using the Effective Daily Recovery Capacity calculation.[60] This calculation overestimates the amount of oil that can be recovered in Arctic waters, and the calculation must be revised to more accurately reflect actual spill removal capability.[61]

The calculation assumes that oil can be recovered at a rate equivalent to 20 percent of the manufacturer rated oil spill skimmer pump capacity. The discounted oil spill skimmer recovery rate is meant to account for inefficient oil removal due to "available daylight, sea state, temperature, viscosity, and emulsification of the oil being recovered."[62] However it does not take into account the additional oil removal inefficiencies encountered in the Arctic or inefficiencies in the entire oil spill response system.

Oil spill "encounter rate" is a measure of how often oil spill response equipment can reach and remove oil. Arctic encounter rates are lower because oil spill response equipment is often precluded by ice, adverse weather, waves, or other factors that limit the amount of oil encountered and recovered. In the Arctic, oil spill response capabilities are typically limited by the weakest link in the chain, which may be the connection, hose, or fitting that can readily become frozen or clogged with ice, requiring significant system downtime to clear, repair, or thaw the impediment.

As shown by the 2010 Deepwater Horizon oil spill in the Gulf of Mexico, the current oil spill response calculation underestimates the amount of equipment needed, even in temperate waters. Less than 3 percent of the oil was recovered using mechanical (skimming and boom) response equipment,[63] even though BP had more than three times the required amount of oil spill response equipment on-site and skimming.[64] The most effective tool at capturing oil during the Deepwater Horizon oil spill was the capping stack—similar in function to a BOP and intended to contain oil flowing from the well—that eventually was responsible for 17 percent of the 25 percent of oil removed; 5 percent was removed by burning.[65]

The Interior Department hired data management contractor Genwest Systems Inc. and environmental consultant Spiltec to make recommendations and develop an improved model to more accurately estimate the Effective Daily Recovery Capacity calculation. Unfortunately, this work will apply to temperate waters only—it will not include additional inefficiencies encountered in the Arctic, such as ice.[66]

In-situ burning will likely be an important tool when responding to an oil spill in the Arctic, and it was used extensively in the Deepwater Horizon response. Yet burning equipment is not currently part of the oil spill response calculation used to determine adequate equipment levels. What's more, the Interior Department's regulations do not require oil and gas operators to demonstrate they have a minimum amount of burning equipment on hand.

More work is needed to develop an Arctic-specific model to calculate the minimum amount and type of oil spill response equipment needed to remove oil spilled in Arctic conditions.

Pew's recommendations:

- Interior should develop, or require operators to develop, an Arctic-specific oil spill encounter rate model that includes ice and adverse weather, and logistical limitations, and examines both mechanical and in-situ burning-oil removal capabilities.

- Oil spill recovery calculations and minimum equipment requirements should be based on Arctic encounter rate modeling, and the effectiveness of the entire spill response system should be examined. This method would replace the existing Effective Daily Recovery Capacity that examines only skimming-pump capacity reduced to 20 percent.
- The amount of mechanical response and in-situ burning equipment required should be sufficient to clean up the entire spill either alone or in combination, providing responders with a complete, optimized spill response tool kit.

(See Appendix II for additional detail on Arctic oil spill trajectory analyses and mapping standards, oil spill recovery calculations, and minimum equipment requirements for the Arctic, worst-case discharge blowout flow rate and total volume estimation methods, and Arctic oil removal and Arctic oil removal benchmarks.)

Arctic well blowout source control

A well blowout is an uncontrolled release of oil and/or gas from a well when all pressure-control systems on the well or drilling unit have failed.[67] Wellhead systems and drilling rigs have multiple, redundant pressure-control systems installed (e.g., drilling muds, BOPs, and control valves), but all mechanical devices have a failure risk. On a drilling rig, a BOP is the last pressure barrier; if this barrier fails, an uncontrolled well blowout occurs. Control measures at the source of a blowout may include a combination of approaches, among them:

- Installation of a replacement blowout preventer, known as a capping stack.
- Installation of a containment dome over the well to flow oil and gas to a surface processing vessel until the well can be controlled.
- Drilling a relief well.

The amount of oil spilled into the environment during a well blowout will be determined by the time it takes to transport source control equipment to the site and then to cap the well, contain the well so that oil is captured directly from the wellhead and pumped to a surface storage vessel, or drill a relief well to plug the failed well. Minimizing the time it takes to get source control equipment in place and working properly is vital to reducing the amount of oil spilled.

The quickest response will include the use of Arctic-proven equipment and expertise on-site alongside additional equipment available for immediate deployment nearby. Transporting equipment or well control experts from outside of the Arctic could result in unnecessary delays and a larger spill.

Arctic well capping and containment system performance standards

After the Deepwater Horizon blowout was stopped by a system that was able to capture the oil and flow it to the surface for processing, storage, and recovery, the Interior Department began to require certain operators to have access to this type of equipment.[68] Interior issued a temporary Notice to Lessees (expiring in November 2015) requiring well capping and containment systems for all OCS oil and gas drilling projects that use a subsea BOP.

The requirement for an Arctic well capping and containment system should be codified in regulation to ensure this requirement remains in place after 2015. Further, the Arctic Ocean's severe weather conditions require built-for-purpose oil spill response equipment. Temperate water systems will not be suitable in the Arctic. Operators should be required to own or have on contract a system that meets Arctic engineering standards and includes a well capping stack, containment dome, and surface processing vessels to control a blowout. Bringing a system from the Gulf of Mexico would take weeks, and such a system would not be designed for Arctic conditions.

Pew's recommendations:

- Arctic well capping and containment systems should include a capping stack (high-pressure BOP with two blind shear rams) with connections that can flow the well to a surface processing vessel and a containment dome that can be placed over the well if the capping stack does not seal the well, fitted with connections that can flow the well to a surface processing vessel.
- The oil spill response plan should include a complete description of how the Arctic well capping and containment system would provide source control and containment during a blowout.
- Prior to drilling, the capping and containment systems should be physically tested in Arctic conditions,

subject to third-party audit, and, when approved for use, be located in the Arctic and ready to commence operations within 24 hours.

- The capping and containment systems should be built to Arctic engineering specifications and, at a minimum, be capable of preventing gas hydrate formation, handling flow rates at least up to 200 percent of the worst-case discharge, and handling pressure at least up to 125 percent of the maximum anticipated pressure from the well.
- To ensure the systems are capable of controlling the well blowout in the same drilling season and able to remain on-site despite increasingly adverse weather conditions, the system should be equipped to deflect or withstand encroaching ice, supported by Polar Class vessels, and staffed with trained, qualified personnel with Arctic experience who are capable of completing well capping operations.

Arctic relief well rig performance standards

Relief wells are the ultimate well blowout source control measure. Well capping or containment systems may stop or slow the blowout prior to drilling a relief well, but that is not always the case. In the Arctic, there is a very limited window of time to drill a relief well, which only increases the importance of having an Arctic-capable second rig already located in the Arctic to provide immediate assistance. Relief wells are a standard emergency response and are required as a minimum standard in other Arctic countries such as Canada and Greenland. Interior Department regulations do not currently include Arctic relief well rig performance standards.

Pew's recommendations:

- The relief well rig should be a second rig, located in the Arctic, and capable of suspending operations and providing relief well assistance to the rig where the blowout occurred.
- The relief well rig should be on-site within 24 hours if the relief well rig is not drilling another well, or within 48 hours if the relief well is currently drilling another well (and must suspend that well prior to commencing relief well services).
- The relief well rig should be Polar Class, equivalent to or more robust than the rig used to drill the original well requiring relief well assistance, and suitable to drill in Arctic conditions that could last up to 60 days after the last day of approved drilling.
- The relief well rig should be outfitted with necessary supplies and equipment to operate in Arctic conditions and staffed with trained, qualified personnel with Arctic experience who are capable of drilling a relief well.

Arctic emergency well control plans

To ensure heightened levels of preparedness in the Arctic OCS and reduce the amount of time required to respond to a blowout emergency, the Interior Department should require operators to include an Arctic emergency well control plan in their oil spill response plan. These emergency plans would detail the availability of well control measures (such as relief well drilling and well containment) and the steps and time to implement those measures successfully. In the event a blowout occurs, this process will ensure that the Interior Department is already familiar with the operator's response methods, speeding up the well control and relief well drilling approvals needed during an emergency.

Pew's recommendations:

- Oil spill response plans should include a comprehensive Arctic emergency well control plan describing the oil spill source control measures to be implemented by the primary rig, secondary relief well rigs, and well capping and containment equipment. The plan should be site-specific and appropriate for Arctic drilling operations.
- Arctic emergency well control plans should describe planning, preparation, and staging to reduce the time required to stop an out-of-control well; time estimates for successfully implementing the source control measure; a hazards assessment; a confirmation that trained and qualified personnel, equipment, and appropriate support vessels will be on-site to carry out the plan.
- Two alternate relief well locations for each well should be fully identified, permitted, and surveyed for shallow gas, which would save valuable time in the event of an emergency, prior to operations commencing on the primary well site, to ensure the sites are suitable for emergency operations.
- Well control drills to test an operator's Arctic emergency well control plan should be conducted prior to the approval of the final permit to drill.

Arctic well control expert contracts

Operators should have a well control expert with Arctic experience on-site during drilling operations. Most operators currently working in the U.S. Arctic indicate that they have contracted with a well control expert and that the expert typically can be flown in from the Gulf of Mexico, Canada, or the United Kingdom to assist in a well blowout. Regulations, however, do not require evidence of a contract with a well control expert that has specific experience in Arctic conditions and in drilling through permafrost and methane gas hydrates, and dealing with remote logistical challenges, ice, and freezing temperatures.

Pew's recommendations:

- Evidence of a signed contract with an Arctic well control expert should be provided in the oil spill response plan application. This contract should cover the entire permitted drilling period, or the drilling permit should be limited to the period when the contract is valid.
- Arctic well control experts should be present on the rig from the beginning of well drilling and remain on the rig until the well is plugged and abandoned.

(See Appendix II for additional detail on Arctic well capping and containment system performance standards, Arctic relief well rig performance standards, Arctic emergency well control plans, and Arctic well control expert contracts.)

Arctic oil spill response equipment and personnel

Technology that was developed to respond to oil spills in temperate waters cannot simply be transferred to the Arctic. Similarly, oil spill response skills developed in temperate waters to do not necessarily translate in the Arctic. The sea ice, high winds, freezing temperatures, and dense fog demand specific equipment and personnel trained to work in those conditions. Current Interior Department regulations do not specify minimum standards for Arctic mechanical or in-situ burning response equipment or the need for specialized training to operate that equipment in harsh Arctic conditions.

Unlike the Gulf of Mexico, where significant shore-based infrastructure and ready access to additional spill response equipment exist, the Arctic's remoteness could delay shipment of additional equipment from outside of Alaska and subarctic Alaskan ports. The nearest major port, Dutch Harbor, is more than 1,000 miles away. Oil and gas operators often rely on oil spill removal organizations to help fulfill their spill response planning requirements. These organizations serving oil and gas exploration and production operators in the U.S. Arctic OCS should also have to meet these minimum equipment and training standards.

Polar Class support vessel requirements for responding to an Arctic oil spill

To be successful, Arctic oil spill response operations need to be supported by Polar Class vessels that are capable of safely operating in ice-infested waters, especially if spill response activities could continue into fall freeze-up conditions. Current Interior Department and Coast Guard regulations do not require that Polar Class vessels be used in oil spill response activities.

It is important that operators have enough Polar Class vessels to support safe operation, provide towing assistance, and support source control and spill response.

Pew's recommendations:

- Oil and gas operators should be required to provide a sufficient number of Polar Class or equivalent vessels as well as ice-capable shallow draft vessels dedicated to supporting nearshore and shoreline oil spill response operations.
- The number and type of vessels should be determined by the Interior Department, in consultation with the Coast Guard, based on a site- and project-specific analysis.

Arctic mechanical response equipment and training standards

Arctic conditions—including ice, freezing temperatures, and dense fog—can affect the efficiency of the mechanical response equipment used to collect and skim oil from the surface of the water and the ability of response personnel to do their jobs effectively. Slush ice, for example, can clog skimmers, and low temperatures can freeze the hoses used to move the oil to a storage container, making the skimmer unusable for hours or days until thawed.

Pew's recommendations:

- Arctic mechanical response equipment and training standards should be established to ensure there is sufficient in-region capability to respond to the oil spill, including sufficient Arctic-grade equipment and personnel trained to operate that equipment.

- Personnel should have training and qualifications in Arctic mechanical response and deployment operations and that vessel captains have experience navigating in the Arctic.
- Arctic-grade equipment should include, but not be limited to, Arctic-grade skimmers, ice-boom, and viscous oil pumps for when the cold water thickens the oil; winterization enclosures and heating systems to protect equipment and prevent freezing; cold-weather gear for personnel; and vessels capable of operating in ice-infested waters.

Arctic oil spill removal organization standards

The Coast Guard has a voluntary program in which oil spill removal organizations can be classified to respond to spills in various types of water, including rivers and canals, the Great Lakes, and inland, nearshore, offshore, and open ocean.[69] These general standards do not account for the unique climate conditions found in the Arctic. The offshore classification, for example, is focused on meeting mechanical response requirements in temperate waters. An oil spill removal organization only equipped to operate in temperate waters could receive approval to operate in the Arctic without any specialized Arctic-grade equipment, training, or expertise and be listed in an oil and gas operator's oil spill response plan. The Interior Department relies on the Coast Guard classifications for oil spill removal organizations in its assessment of whether operators in U.S. OCS waters meet federal spill response requirements.

Pew recommends the Interior Department, with Coast Guard guidance, revise its regulations to require mandatory minimum equipment, training, and qualification standards for Arctic OCS oil spill removal organizations to ensure sufficient ability to remove oil offshore in a range of Arctic conditions.

Pew's recommendations:

- Oil spill removal organizations serving the Arctic OCS should be required to have Arctic equipment capable of operating offshore in nearshore and deeper waters, including Polar Class vessels, Arctic-grade skimmers, and in-situ burning equipment.
- Personnel should be trained on the safe and effective use of mechanical response tools and in-situ burning, be familiar with Arctic operations and safety standards, and have experience navigating vessels in ice and ice fog.
- The Interior Department should create a classification for the Arctic Ocean. Unlike the Coast Guard's existing voluntary program, these requirements should be mandatory for Arctic OCS exploration and production operations and be verified through inspections and field tests of equipment and tactics.

Arctic oil recovery storage standards

There are no minimum storage standards for Arctic oil and gas operations in the event of a blowout. The remote location of drilling operations, limited logistical access, and adverse weather can delay the arrival of additional storage capacity.

Pew's recommendations:

- Interior should require a sufficient amount of on-site and in-region recovered oil storage and pump capacity, including primary and secondary storage capacity sufficient to recover the amount of spilled oil without impeding spill response operations.
- Interior should require standards that account for seawater trapped in the spilled oil, seawater collected during the skimming process, and remote logistical access and weather delays.
- Arctic storage systems that have the capability to heat and separate oil-water emulsions and unload the water while storing the oil to maximize oil recovery and storage.

(See Appendix II for additional detail on Arctic oil spill removal organization standards, Polar Class support vessel requirements for Arctic oil spill response, Arctic mechanical response equipment and training standards, Arctic in-situ burning equipment and training standards, Arctic dispersant use guidelines, and Arctic oil recovery storage standards.)

Arctic oil spill response equipment testing and verification

Arctic OCS oil spill response plans are currently approved without requiring an oil and gas operator to successfully demonstrate and verify under Arctic field conditions that its oil spill response equipment, personnel, and tactics will be effective in Arctic conditions. Oil spill response plans are approved under assumptions about what might work in Arctic conditions. Operators are required only to field test their plans over the course of three years while exploration, development, or production operations are underway, during which time the Interior Department may find the operator is unprepared, or an accident may occur before testing is complete. To ensure high levels of preparedness, plans should be field tested and verified in advance of operations.

Additionally, special attention should be paid to field testing of tactics, strategies, and equipment used to protect environmentally sensitive areas. The Coast Guard's Incident Specific Preparedness Review after the Deepwater Horizon blowout identified several gaps in the protection strategies for environmentally sensitive areas. The review recommended that the Coast Guard, in coordination with other agencies, including the Department of the Interior, develop best practices for identifying sensitive areas, develop and test protection strategies for these areas, and ensure that trained personnel and adequate response resources are available to carry out those strategies.[70]

Arctic offshore field tests to verify spill response tactics and strategies prior to operation

Field tests can validate spill response technologies and strategies, and the training of spill responders. Spill response limitations identified during field testing also can aid the Department of the Interior in establishing preventative measures for drilling, such as seasonal restrictions.

Pew's recommendations:

- Interior should require oil and gas operators in the Arctic OCS to plan for and conduct field tests prior to conducting any OCS drilling operations in order to verify that Arctic spill response techniques, equipment, and methodologies will be effective and are the best available technology for use in the Arctic. The field tests should use nontoxic oil spill simulant materials to test the efficacy of the tactics and strategies proposed.
- Interior should maintain an approved list of Arctic oil spill response tactics, including information on which company or oil spill response organization has successfully tested the tactic, when it was approved, the type of equipment required to accomplish that tactic, and the estimated oil recovery rate.

Protection of Arctic resources of special economic, cultural, or environmental importance

The Arctic is subject to severe weather, but it also sustains a variety of marine mammals and seabirds that make extensive use of its waters. In addition, indigenous residents of Arctic communities have lived an irreplaceable way of life interwoven with this ecosystem, which has endured for thousands of years. They are an integral part of the region's rich ecosystem. For many residents of the Arctic, there is a direct connection between the continued health of the marine environment and the health of their food supply, their culture, and themselves.

Arctic communities should play a major role in identifying and prioritizing important areas in nearshore and offshore regions. Indigenous Arctic peoples have developed and maintained traditional knowledge about the environment that is essential for identifying and prioritizing areas important for their subsistence, culture, and health of the ecosystem. Local knowledge also proves invaluable in determining safe routes and access points to these sensitive sites during a spill response.

Geographic response strategies are oil spill response plans tailored to protect specific sensitive areas from impacts of a spill. These map-based strategies show oil spill responders where sensitive areas are, where to pre-stage and place oil spill protection resources, and specify the time, equipment, and personnel needed to carry out the plan. The Alaska Department of Environmental Conservation has developed geographic response strategies for many areas of Alaska, but there are no such strategies of the same caliber for the federal waters in the Chukchi or Beaufort seas.

Alaska Clean Seas, an oil spill removal organization serving the North Slope of Alaska, has identified a few environmentally sensitive area protection plans for the Beaufort and Chukchi seas. However, most of these sites have not been tested by spill responders to verify access or effectiveness, and very few have pre-staged equipment in place.

The Interior Department must take a careful look at the potential impact of oil and gas exploration, development, and production on subsistence resources, and show its commitment to ensuring these resources are protected. Current regulations require oil and gas operators' oil spill response plans to include strategies for protecting special economic, cultural, or environmentally important areas. But the regulation does not establish specific performance standards for the amount, type, and location of pre-staged oil spill response equipment to be dedicated to special area protection.

Pew's recommendations:

- The Interior Department should ensure that oil spill response plans identify resources of special economic, cultural, or environmental importance that could be affected by the worst-case discharge oil spill trajectory, describe strategies for their protection, and demonstrate that those strategies work by field testing them prior to drilling or operating in those areas.
- Arctic communities should play a major role in identifying and prioritizing important nearshore and offshore areas for protection during an oil spill.
- Oil and gas operators should demonstrate that they have adequate pre-staged response equipment near the sites and personnel dedicated to carrying out these protection strategies.
- Geographic response strategies should be developed, tested, and proved effective to protect the identified special areas.

(See Appendix II for additional recommendations on Arctic offshore field tests to verify spill response tactics and strategies prior to OCS operation, and on protection of Arctic resources of special, economic, cultural, or environmental importance.)

Public participation and transparency in Arctic drilling plans and operations

After the Deepwater Horizon blowout, there was a renewed effort to enhance U.S. government oversight of offshore oil and gas operations. Important lessons learned included the need for interagency coordination, especially when other agencies hold valuable expertise, and increased transparency. The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling recommended that the Interior Department "create a rigorous, transparent, and meaningful oil spill risk analysis and planning process for the development and implementation of better spill response."[71]

The commission also recommended that a joint agency and public review of draft oil spill response plans be completed and that the final oil spill response plans be made available to the public once they are approved.[72] The need for oversight, coordination, and transparency was echoed in the Interior Department's 60-day "Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program."[73]

The Interior Department should make information related to oil and gas management processes, decision-making and activities available to the public in a timely fashion and on a proactive basis. Relatively simple steps—such as publishing letters, approvals, and inspection and testing data on its website—would go a long way toward building trust and improving public participation in the oil and gas decision-making process. Interior should also accept public comments on oil spill response plans before they approve them.

Public and joint agency review process for Arctic oil spill response plans

Exploration, development, and production plans of oil and gas operators are subject to public review and comment,[74] but it should also be the practice of the Interior Department to provide an opportunity for public review and comment on oil spill response plans. Interior did provide the opportunity for public comment on Shell Oil's 2012 Chukchi Sea oil spill response plan and conducted a joint agency review in order to implement lessons learned from the Deepwater Horizon blowout in the Gulf of Mexico. A public comment period and joint agency review process should be codified in regulation and should consistently apply to future submitted oil spill response plans.

There is heightened, broad public interest in oil spill response plans by academics, local governments, state governments, other federal agencies, and nongovernmental organizations in the Arctic. The public should have a voice in what kind of oil and gas development is appropriate, where it should take place, and what safeguards are needed. Indigenous residents' traditional knowledge and concerns should be a critical piece of any decisions made about development in the Arctic.

Pew's recommendations:

- The Interior Department should ensure that there is a process for a 60-day joint agency and public review of Arctic OCS oil spill response plans before approving them.
- Public comments on Arctic OCS oil spill response plans should be addressed in a findings document in which Interior explains how it addressed the comments received and it provides regulatory and technical explanations to support its decision.

The Arctic Ocean is one of the world's last relatively untouched marine ecosystems, providing habitat for such important species as bowhead whales.

Public access to Arctic exploration and production facility inspections and audits

One way of ensuring strong government and public oversight of activities in the U.S. Arctic OCS is for the public to have access to documentation that verifies oil and gas operators are meeting requirements. The Environmental Protection Agency, for example, maintains a public searchable database called Enforcement and Compliance History Online, or ECHO. This website tracks information on facility compliance and includes inspection, violation, and enforcement information for the Clean Water Act, Clean Air Act, and hazardous waste laws.[75] Some state oil and gas agencies, including Alaska's Department of Environmental Conservation,[76] also provide public access to permits, compliance data, and contaminated site data.

Pew's recommendations:

- The Interior Department should also provide public access to compliance and enforcement data for Arctic OCS oil and gas operations by making such information available on its websites on a timely and proactive basis, including:
    - Published letters and approvals.
    - Results of tests, inspections, announced and unannounced oil spill exercises.
    - Audits and certifications, including by independent third parties, of critical Arctic equipment such as primary and relief well drilling rigs, vessels, and source control tools (BOPs and capping and containment systems).
    - Compliance and enforcement data.

(See Appendix II for additional recommendations on public and joint agency review process for Arctic oil spill response plans and public access to Arctic exploration and production facility inspections and audits.)

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Appendix I

Proposed Arctic Operations Improvements for the Outer Continental Shelf

Recommended Improvements to the Department of Interior's
Title 30, Mineral Resources
Chapter II, Bureau of Safety and Environmental Enforcement
Department of the Interior, Subchapter B, Offshore
Part 250, Oil and Gas and Sulphur Operations in the Outer Continental Shelf
Part 550, Oil and Gas and Sulphur Operations in the Outer Continental Shelf

Contents

List of abbreviations

AHV	Anchor Handling Vessels
APD	Application for a Permit to Drill
API	American Petroleum Institute
ARRT	Alaska Regional Response Team
BACT	Best Available Control Technology
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BOP	Blowout Preventer
CBL	Cement Bond Log
CET	Cement Evaluation Tool
CFR	Code of Federal Regulations
CIDS	Concrete Island Drilling Structure
CO	Carbon Monoxide
COCP	Critical Operations Curtailment Procedures
DNV	Det Norske Veritas
DOI	Department of Interior
DPP	Development and Production Plan
EP	Exploration Plan
EPA	Environmental Protection Agency
GBS	Gravity Based Structure
HSE	Health, Safety, and Environment
ICS	Incident Command System
IMO	International Maritime Organization
ISB	In-Situ Burning
ISO	International Standards Organization
MACT	Maximum Air Control Technology
MLC	Mud-Line Cellar
MODU	Mobile Offshore Drilling Unit
NAE/NRC	National Academy of Engineering/National Research Council
NEB	Canada National Energy Board
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NO_2	Nitrogen Dioxide
OCS	Outer Continental Shelf
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and Quality Control
ROV	Remotely Operated Vehicle
SDC	Steel Drilling Caisson
SO_2	Sulfur Dioxide
SSDC	Single Steel Drilling Caisson
TSP	Total Suspended Particulates
USCG	U.S. Coast Guard

Arctic OCS equipment design and operating performance standards based on worst-case historic conditions

Proposal: The Department of the Interior's regulations at Title 30 Code of Federal Regulations Part 250 (30 CFR § 250) and 30 CFR § 550 should require Outer Continental Shelf, or OCS, oil and gas operators to assess the historic conditions at the proposed exploration, development, and production location and use a conservative assessment of that data as the basis for establishing equipment design and operating performance standards for projects proposed in the Arctic OCS.

All equipment used to explore for and develop hydrocarbons, including but not limited to vessels, pipelines, wells, tanks, processing equipment, and structures, should be designed in accordance with Arctic engineering practices and should be able to withstand the worst-case geological hazards, Arctic temperatures, wind, wave, storm surges, coastal erosion, currents, and ice hazards that may be encountered. Design and operating performance standards should be based on conservative estimates using actual measurements of the worst-case historic conditions in recorded history for the site of development. Where historic data is incomplete, hind-cast methods can be used to develop conservative design and planning estimates.[1, 2, 3, 4]

Rationale: Interior Department regulations at 30 CFR § 250 and 30 CFR § 550 have very few Arctic-specific design and operating standards. Existing regulations do not specifically require OCS operators to assess the historic conditions at the proposed exploration and development location or use a conservative assessment of that data as the basis for establishing equipment design and operating standards for projects proposed in the Arctic OCS. The current Arctic-specific standards only include a requirement to:

- Demonstrate that Mobile Offshore Drilling Units, or MODUs, are capable of performing at the proposed drilling location, including a third-party review of the MODU for use in a frontier area. 30 CFR § 250.417.
- Install a subsea blowout preventer, or BOP, in a well cellar in ice-scour areas. 30 CFR § 250.451(h).
- Install and operate oil and gas production safety systems accounting for ice, icing, and freezing conditions. 30 CFR § 250.800(a).
- Site platforms taking into account ice-scour risk. 30 CFR § 250.906(a)(6).
- Take additional precautions for pipelines in ice and permafrost. 30 CFR § 250.1007(a)(4).
- Submit Emergency Plans and Critical Operation Curtailment Procedures for Exploration and Production Operations in Alaska. 30 CFR § 550.220 and 30 CFR § 550.251.
- Submit support vessel, offshore vehicles, and aircraft, including any ice management vessels that will be used in Exploration and Production Operations, but does not make mandatory the use of Polar Class vessels. 30 CFR § 550.224 and 30 CFR § 550.257.

The Arctic Ocean's seasonal weather is unlike any other oil and gas operating area in the United States. Even during the summer, when sea ice is at its lowest extent, there is the potential for ice, dense fog, storms, high winds and waves, and freezing temperatures.[5] Therefore, it is important to take these risk factors into account.

Sea Ice: Facilities designed to withstand ice for the Beaufort and Chukchi seas need to be roughly 10-20 times stronger than the designs of large temperate water Gulf of Mexico platforms built for hurricanes and rough seas or subarctic Cook Inlet platforms built for ice and storm events.[6] Offshore facilities designed for the temperate waters of the Gulf of Mexico or subarctic waters of Alaska's Cook Inlet are not suitable for use in the Arctic.

The Arctic Ocean (including the Beaufort and Chukchi seas) is normally frozen for eight to nine months of the year (November through June or July). Sea ice typically begins to melt in June and July, a period called "break-up." The U.S. Arctic Ocean is relatively free of ice from July through September—a period referred to as the "open water season." In October (in the Beaufort Sea) and early November (in the Chukchi Sea), the ice begins to form again in a period called "freeze-up."

First-year ice thicknesses range from approximately 5.9′-6.5′ in the Beaufort Sea to 3.9′-4.9′ in the Chukchi Sea. Multiyear ice thicknesses for both the Beaufort and Chukchi seas range from 9.8′ and upwards of several hundred feet thick. For example, the Interior Department reports that pressure ridge keels can be thick enough to gouge the seafloor out to approximately 165′ water depth in some areas.[7, 8] Sea ice can damage offshore structures and vessels and can limit transportation and resupply options.

The Arctic Ocean contains different types of ice that range in thickness, age, and strength.[9] Facilities must be designed for: new first year ice that can be five to 7′ thick;[10, 11] multiyear floes that can be miles wide, miles long, and 10s to 100s of feet thick; and icebergs.

A 2012 joint oil and gas industry and Interior Department study[12] concluded that, "The design of offshore structures for the western Arctic of North America is likely to be governed by their interactions with very large and thick ice features which include ice islands, multi-year hummock fields and large multi-year floes with embedded ridges. … Extreme Ice Features are transported from the High Arctic via the Beaufort Gyre and enter the southern Canadian and Alaskan Beaufort Seas and the US Chukchi Sea."

For example, six large multiyear ice flows in the Chukchi Sea have occurred since 2000, with the largest floe estimated to be 300′ wide, 12 miles long with a 90 percent ice concentration.[13] In February 2012, two large pieces of ice were discovered off the Chukchi Sea coast. The larger one was estimated to be 260′ long, 131′ wide, and 66′ above sea level. In 1992, a massive ice floe was present in the U.S. Beaufort Sea that was several miles in width and length and was so thick that it grounded out even in water depths of 105′.[14] By the end of winter (June), the median ice floe diameter is estimated to be approximately 2 miles long in the Beaufort and Chukchi seas, with the largest ice floe estimated at 27 miles long.[15]

Freezing Temperatures: The mean summer temperature for Barrow (the community directly between the Chukchi and Beaufort seas) is typically 38 degrees Fahrenheit with temperatures dropping steadily in October to a mean of 11 F, and barely registering above zero in November.[16] During winter months, temperatures drop to minus 50 F,[17] dipping even lower when wind chill factors are considered. Freezing temperatures can adversely affect the ability of equipment and humans to operate. Freezing temperatures combined with high winds and waves can coat vessels and equipment with ice, impairing its ability to function properly. In the month of October, vessel icing from sea spray can be the primary reason that vessels leave the region, rather than the threat of pack ice forming.[18]

Winds: The Beaufort Sea prevailing wind direction is from the east and northeast. The 100-year maximum wind is estimated to be 98 knots (113 mph). The Chukchi Sea prevailing wind is from the northeast. The 100-year maximum wind is estimated to be 62 knots (71 mph).[19] Winds gain in speed during the summer months, with an average maximum wind speed of 30 knots (34 mph) occurring in October.[20] In Barrow, the daily average wind speeds can reach up to 14 mph by October, with maximum gusts up to 67 mph.[21] Winds traveling over greater areas of open water (due to the decreasing ice extent in summer) can lead to greater wave heights and storm surges.

Waves: Wind and wave conditions can impede transportation and resupply options, and hinder emergency response operations. Based on traditional knowledge, the expected maximum wave heights for the Beaufort Sea is 22.5′ and 28.5′ for the Chukchi Sea.[22] The U.S. Army Corps of Engineers estimated the maximum wave height for the nearshore Beaufort Sea area to be 20′,[23] and other scientists estimated wave heights of up to 30′ in the deeper waters (up to 100′).[24] The Minerals Management Service estimated a maximum wave height of 29′.[25]

Fog and Seasonal Daylight: Fog can reduce visibility for air and marine pilots conducting transportation, resupply, and emergency response operations. Fog is more common during the summer open water months as warmer air interacts with cold water. Barrow averages 15 days of fog per month and 6.5 days of heavy fog per month from June through October.[26]

The amount of daylight in the Arctic changes drastically during the year with 24 hours of daylight from mid-May until mid-August. As the summer months pass into autumn, the total hours of daylight decrease rapidly, until the Arctic is in complete darkness from mid-November until mid-January. Seasonal darkness can limit operational and emergency response activities.

Arctic OCS pipeline performance standards

Proposal: A requirement for Arctic OCS pipeline performance standards should be added to the Interior Department's regulations at 30 CFR § 250 to enhance the existing OCS pipeline regulations. Arctic offshore pipelines should be designed to: withstand Arctic conditions; use redundant system design; include a robust inspection, monitoring, and repair program; and include immediate source control methods to evacuate the line. More specifically, regulations should require that:

- Pipelines be buried below the seabed ice gouging depth[*, †, 27] and ice strudel scour depth,[‡, 28] and be designed to minimize permafrost thaw subsidence.[§]
- Pipelines be constructed using double-walled pipe, a utilidor, or a pipe-in-pipe system to provide a redundant

* 30 CFR § 250.1003(a)(1) requires pipelines to be buried at least 3′ in water depths less than 200′; however, Arctic pipeline burial depth may need to be double (6′) or triple (9′) the current standard, buried to a site-specific depth based on the deepest anticipated ice gouge and straddle scour depth.

† Icebergs that drift into shallower water may drag along the seafloor, gouging along the way. When two floes of pack ice run into each other, a pressure ridge may form with ice rubble building above and below the surface. The ice rubble below the surface and the bottom of the iceberg may dig into the seafloor and cause a problem for buried pipelines.

‡ "Strudel" means "whirlpool" in German. Strudel scour describes an event where, during spring melt, a large volume of freshwater flows onto pack ice and drains through a hole or crack in the ice creating a severe whirlpool down to the seabed where the pressure of the water can wash layers of the seabed away, creating a hole more than 12′ deep.

§ 30 CFR § 250.1002(f) requires that "Pipelines shall be designed and maintained to mitigate any reasonably anticipated detrimental effects of water currents, storm or ice scouring, soft bottoms, mud slides, earthquakes, subfreezing, temperatures, and other environmental factors." This should be revised to read: "Pipelines shall be designed and maintained to mitigate any reasonably anticipated detrimental effects of water currents, storm or ice gouging and ice scouring, soft bottoms, permafrost, mud slides, earthquakes, subfreezing, temperatures, and other environmental factors. Pipelines should be buried below the seabed ice gouging depth and ice strudel scour depth, and be designed to minimize permafrost thaw subsidence."

pipe wall for secondary containment of oil in case of a leak.[*, 29]

- Pipelines be equipped with automated emergency shutoff valves to isolate the pipeline. The emergency shutdown valve and its actuating mechanism should be protected from damage arising from fire, explosion or impact.[†, 30]
- Two leak detection systems be installed on the pipeline to provide redundant leak monitoring capability.[‡, 31] Leak detection should include leak monitoring in the interstitial space between the double-walled pipe, utilidor or pipe-in-pipe system. An additional, redundant leak detection system should be installed[32] (e.g., a pressure and temperature compensated metering and mass balance system that meets regulatory-specified levels or performance based on leak size and time to detect the leak).[§, 33] Leak detection systems should be equipped with automated visual and auditory alarms and should be tested prior to pipeline use, and at regular intervals thereafter.[34]
- Pipelines be designed and operated to prevent corrosion, including use of corrosion control coatings, cathodic protection systems, corrosion inhibitors, and maintenance practices (e.g., maintenance pigging)[¶, 35] that prevent pipeline corrosion for the operating life of the pipeline.[**, 36] Corrosion control programs should be instituted immediately due to inability to access buried Arctic pipelines at a later date for repair.
- Pipelines be hydrotested prior to use[37] and inspected using a smart pig inspection device[38, 39] at least annually

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* The most recent offshore, subsea pipelines installed in the U.S. Beaufort Sea include the 2008 Pioneer Oooguruk and the 2009 Eni Nikaitchuq pipeline. Both pipelines were designed and installed using a pipe-in-pipe design where a hydrocarbon flowline was placed inside a larger diameter pipeline that provides secondary containment to capture a leak from the hydrocarbon flowline if one were to occur. The interstitial space (the annular space between the two pipelines) can be monitored for hydrocarbon leaks. The 2008 Pioneer Oooguruk pipeline is a 5.7 mile long pipeline that connects the offshore production facility placed on a gravel island to shore. The Oooguruk pipeline used a pipe-in-pipe design including: a 12" multiphase pipeline that was placed inside a 16" pipeline that provides secondary containment. http://www.offshore-technology.com/projects/premier_ooguruk/, accessed April 2013. The 2009 Eni Nikaitchuq pipeline is a 3.5 mile long pipeline that connects the offshore production facility placed on a gravel island to shore. The Nikaitchuq pipeline used a pipe-in-pipe design including: a 14" multiphase pipeline that was placed inside a 18" pipeline that provides secondary containment. http://www.offshore-technology.com/projects/nikaitchuqoilfieldal/, accessed April 2013.

† United Kingdom, The Pipelines Safety Regulations 1996, No. 825, Schedule 3, Emergency Shut-down Valves, require pipelines to be equipped with automated emergency shutoff valves to isolate the pipeline, and the emergency shutdown valve and its actuating mechanism be protected from damage arising from fire, explosion, or impact, 2013.

‡ All three subsea pipelines installed in the U.S. Beaufort Sea (BP's Northstar pipeline, Eni's Nikaitchuq pipeline, and Pioneer's Oooguruk pipeline) all have redundant leak detection systems installed as best technology. These pipelines were installed in state waters. The State of Alaska, Department of Environmental Conservation requires operators to install best available technology, or BAT, to prevent leaks from facilities that hold and transport oil (Alaska Statute 46.04.030(3)). Redundant leak detection systems were determined to be BAT.

§ 30 CFR § 250.1004(b)(1)(5) states that *"The Regional Supervisor may require that oil pipelines be equipped with a metering system to provide a continuous volumetric comparison between the input to the line at the structure(s) and the deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect variations between input and discharge volumes. In lieu of the foregoing, a system capable of detecting leaks in the pipeline may be substituted with the approval of the Regional Supervisor."* The current regulation states that the Interior Department may require, but does not make mandatory a mass balance leak detection system. The regulation provides Interior with the authority to require a leak detection system, but does not make it mandatory nor include any leak detection performance standards.

¶ BP and ConocoPhillips reported to the Alaska Department of Environmental Conservation at a 2007 Conference on Pipeline Pigging that: "Debris encountered inside the pipelines may include wax, sand, corrosion by-products, carbonate scale, and/or water; … increased pigging frequency is necessary where debris accumulates rapidly in the pipeline during normal operations; and there are no industry standards for the frequency of maintenance pigging, or for measuring the effectiveness of a maintenance pig run." Therefore there is a need to establish minimum maintenance pigging requirements in regulation.

** 30 CFR § 250.1002(e) requires that *"Pipelines shall be provided with an external protective coating capable of minimizing underfilm corrosion and a cathodic protection system designed to mitigate corrosion for at least 20 years." This requirement should be revised to include the use of corrosion inhibiting agents and a requirement for the coating and cathodic protection system to be effective for the entire design life of the pipeline, not just 20 years.*

thereafter.[*, 40] Pipelines be inspected by a certified pipeline inspection engineer and approved for continued use prior to returning the pipeline to service. Pipeline inspection standards should be specified in regulation.

- Pipeline systems be equipped with pig launching and receiving facilities to examine for wall loss (corrosion and erosion) and to run maintenance pigs.[†, 41, ‡, 42]
- Drilling unit and offshore facility piping be designed either with a leak detection system, or fully enclosed, to ensure complete capture of any leak that could occur.
- Pipelines be capable of completely evacuating the pipeline either to an offshore facility or to an onshore storage location or pipeline system in the event a leak is identified.
- Annual seabed bathymetry surveys be conducted along the offshore pipeline route to monitor seabed elevation changes (e.g., depressions formed by ice gouging and strudel scours, wave-induced seabed currents that redistribute trench backfill soil, and thaw subsidence).[§]
- Annual surveillance of the shore crossing be completed to identify and address coastal erosion where the pipeline landfalls.

Rationale: The Interior Department does not currently have a full suite of Arctic-specific OCS pipeline leak detection and prevention design standards in its regulations. The Interior Department's regulations at 30 CFR § 250.1000-§ 250.1008 set some standards for OCS pipelines and associated valves, flanges and fittings in the OCS, unless the pipeline is regulated under Department of Transportation Regulations at 49 CFR § 192 or 49 CFR § 195. As footnoted in the recommended pipeline standards, on the previous pages, the existing Interior Department OCS pipeline standards include a number of important requirements for OCS pipelines, but do not include all the specific Arctic standards recommended above. For example, 30 CFR § 250.1007(a)(4) does require a description of additional precautions for pipelines in ice and permafrost; however, it does not include any mandatory, specific Arctic design requirements.

To date there have been four offshore Arctic pipelines built in the U.S. Beaufort Sea: (1) BP's 1988 Endicott pipeline located above water on a gravel causeway; (2) BP's 2001 Northstar subsea pipeline; (3) Pioneer's 2008 Oooguruk subsea pipeline; and (4), the 2009 Eni Nikaitchuq subsea pipeline. No offshore pipelines have been installed in the Chukchi Sea. All four of these Beaufort Sea pipelines were built without the benefit of any Arctic-specific pipeline construction and oil spill prevention standards in the Interior Department's regulations. The American Petroleum Institute's, or API's, 1995 Recommended Practice for planning, designing and construction of pipelines in the Arctic, (API RP 2N), provided some initial guidance; however, many lessons have been learned from actual Arctic pipeline construction and operation.[43] API has plans to update this standard in the future.

Future subsea pipelines in the Beaufort Sea will draw heavily from the design and best practice successes of BP's

* 30 CFR § 250.1003(b)(1) requires pipelines to be hydrotested to at least 1.25 times the Maximum Allowable Operating Pressure, or MAOP, for at least 8 hours when installed; however, 30 CFR § 250.1005 (a) does not specify mandatory inspection methods or intervals for the pipelines after initial installation, instead it only requires that "*Pipeline routes shall be inspected at time intervals and methods prescribed by the Regional Supervisor for indication of pipeline leakage.*"

† 30 CFR § 250.1007(a)(2) requires the operator to provide a pipeline schematic showing any proposed pig launchers and receivers, but does not make mandatory the installation of the pig launchers and receivers, or make mandatory the periodic use of smart pigs and maintenance pigs on OCS pipelines.

‡ Alaska Department of Environmental Conservation, Draft Conference Proceedings Report, 2006 Maintenance and Intelligent Pigging Conferences, Draft Report February 2007, stresses the importance of pig launching and receiving facilities included in the original pipeline design, otherwise maintenance and intelligent pig ("smart pigging") is not possible on that pipeline.

§ Weather and ice conditions can result in seabed changes that vary from year to year.

2001 Northstar, Pioneer's 2008 Ooogurak and the 2009 Eni Nikaitchuq subsea pipeline installations and be modified to avoid lessons learned.[44]

The largest U.S. Beaufort Sea pipeline installed as of 2013 is an 18″ pipeline installed at BP's Northstar facility in a maximum water depth of 37′ reaching 6 miles offshore.[45] The Northstar pipeline was buried in a 6-9′-deep trench in the seabed floor and covered with seabed soil and was equipped with two leak detection systems.

In 2008 a 12″ multiphase production flowline was installed inside a 16″ pipeline (serving as secondary containment for the oil line) at Pioneer's Oooguruk facility in a maximum water depth of 7′ reaching 5.7 miles offshore. The Oooguruk pipeline was buried in a 6′-deep trench in the seabed floor and covered with seabed soil and was equipped with two leak detection systems.[46]

In 2009 a 14″ multiphase production flowline was installed inside an 18″ pipeline (serving as secondary containment for the oil line) at Eni's Nikaitchuq facility in a maximum water depth of 10′ reaching 3.5 miles offshore. The Nikaitchuq pipeline was buried in a 6′-deep trench in the seabed floor and covered with seabed soil and was equipped with two leak detection systems.[47]

Engineering study and design of these three offshore subsea, buried pipelines resulted in a number of important lessons learned, as well as Arctic engineering best-technology standards, which are included in the Arctic OCS pipeline recommendations listed above. For example, Arctic pipelines must be buried below the seabed to avoid ice damage from ice gouging (icebergs, and ice pressure ridging), strudel scour, and must be designed to withstand bending stresses on the pipeline due to permafrost thaw subsidence. In water depths less than 200′, pipelines must be trenched to avoid excessive ice loading, hydrodynamic loads, localized seabed erosion, spanning and upheaval buckling.[48] Subsea pipeline installation in water depths from approximately 65′ to 130′ must account for more severe ice gouging.

Installation of offshore pipelines in water depths more than 37′ has not yet been attempted in the U.S. Beaufort Sea or Chukchi Sea.[49] Pipeline installation in deeper waters will need to be installed from floating vessels rather than from shorefast winter ice (the current installation method).

In 2000, prior to the installation of Oooguruk and Nikaitchuq pipe-in-pipe pipeline designs, the Interior Department commissioned a study of double wall versus single wall Arctic pipelines.[50] C-Core, the authors of the 2000 Interior Department pipeline study, acknowledged the lack of real-world data on double-walled Arctic pipelines installed as of 2000, yet, even with limited data, C-Core concluded there are many advantages to double-walled pipelines. C-Core concluded that the main advantages of a double-walled pipeline are: substantially lower corrosion rate on the interior pipeline; ability to monitor the annulus for a leak; containment of a leak; and, the likelihood of a leak in both pipes is extremely low. C-Core found that the main advantages for a single-wall pipe were primarily economic, including: simpler construction; lower construction costs; and, lower life-cycle costs. Overall C-Core concluded that: "double wall pipeline configurations offer moderate-to-significant operating and maintenance advantages relative to single wall pipelines because of the ability for secondary containment of oil in the event of an inner pipe failure."[51] The 2000 Interior Department study needs to be updated to include actual pipeline design installation and operating experience from the decade that has elapsed.

Ice-rich permafrost is consistently found near the shoreline out to water depths of at least 5′; beyond the 5′ isobaths, subsea permafrost may be found at varying depths below the mud line. Warm pipelines placed in subsea permafrost can cause soil to melt and subside; therefore, a pipeline's thermal effects on the subsea environment warrant careful consideration. Additionally, because the Arctic shoreline is receding, pipeline must be designed with adequate setback distance to accommodate coastal erosion.Arctic OCS pipelines may be in operation year-round, buried below the seabed. Oil spill response may be delayed for up to six months for a pipeline leak located under solid or broken ice. Because Arctic pipelines are inaccessible for external monitoring, maintenance, and repair, Arctic pipelines require a more robust design and additional oil spill prevention systems to be included in the initial installation. The installation of a tank and pump system provides a means to evacuate the pipeline to control a spill, especially during periods when spill response is not possible.

The International Organization for Standardization, or ISO, has developed standards for Arctic Structures (ISO 19906 Code) that consider ice-loading on the structure. Det Norske Veritas, or DNV, is developing a recommended practice for Arctic Structures and Pipelines (DNV-RP-C209); however, as of April 2013 DNV had not published this recommended practice.[52] DNV's recommended practice aims at addressing gaps in the ISO 19906 where the design code structure does not provide implicit or explicit guidance for the design and operation of Arctic pipelines.

Arctic OCS production facility and transportation performance standards

Proposal: A requirement for Arctic OCS production facility performance standards should be added to the Interior Department's regulations at 30 CFR § 250 to enhance the existing production facility regulations and to make clear the preferred production facility and oil transportation methods for the Arctic. The following standards should be included:

- Production facilities (including development drilling) built and installed, after exploration drilling is complete, should be built on a gravel island[*] (in water depths up to 60′)[53] or use a bottom-founded structural design[†, ‡, 54, §, 55, ¶, 56, **, 57, ††, 58] that meets the required year-round Polar Class Rating (in water depths up to

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* All four U.S. Beaufort Sea oil and gas facilities (BP's Endicott Facility, BP's Northstar Facility, Pioneer's Oooguruk Facility, and Eni's Nikaitchuq Facility) are all built on gravel islands in less than 60′ of water. The deepest gravel island is BP's Northstar Facility island in 37′ of water. Gravel islands are proven Arctic facility designs. There are no gravel islands in the Chukchi Sea as of 2013, and the use of gravel islands is unlikely due to the fact that most existing leases occur in water depths that exceed 60′, but less than 250′ where bottom-founded structures could be considered.

† There are no bottom-founded structures installed in either the Beaufort or Chukchi Seas as of 2013.

‡ The Concrete Island Drilling Structure's, or CIDS', Arctic design is an example of a bottom-founded structure built for operation in year-round Arctic conditions in up to 50′ of water. In the past, the CIDS was used to drill exploration wells in the U.S. Beaufort Sea. In 2005, the CIDS was converted into a production platform (and renamed Orland) by Exxon Neftegas Limited and was installed offshore Russian's Sakhalin Island at the Chayvo Field in 2005. A wave-deflector shield and additional earthquake strengthening was added.

§ The Molikpaq structure is an example of a bottom-founded structure built for operation in year-round Arctic conditions of the Beaufort Sea in water depths up to 65′, built by Gulf Canada. The Molikpaq is an octagonal-shaped steel caisson structure used to drill exploration wells in the Canadian Beaufort Sea. See Mastskevitch, D.G., (ExxonMobil Upstream Research Co.), Technologies for Arctic Offshore Exploration & Development, Society of Petroleum Engineering Paper No. 102441, 2006 Russian Oil and Gas Technical Conference and Exhibition, Moscow, Russia, October 2006. The Molikpaq was converted into a production platform (called Sakhalin-2, and renamed the Pitun Astokh-A production platform) offshore Russia's Sakhalin Island by Sakhalin Energy. A wave-deflector shield and additional earthquake strengthening was added. An additional 50.5′ of structure was added to increase the Molikpaq's ability to operate in a water depth of 100′ at 7.5 miles offshore.

¶ The Prirazlomnoye Field is located 37.3 miles offshore in 65′ of water in the Russian Arctic Shelf. The Prirazlomnoye Field design used a bottom-founded gravity caisson.

** The Pitun Astokh-B production platform was installed offshore Sakhalin Island by Sakhalin Energy. The Pitun Astokh-B is a Concrete Gravity Based, or CBC, structure operating in a water depth of 105′ at 7.5 miles offshore.

†† In 1997 ExxonMobil installed the Hibernia gravity-based structure in 263′ of water, 193 miles offshore, in the subarctic location of Grand Banks Offshore Newfoundland, Canada. The Hibernia gravity-based structure was developed for a subarctic environment, and additional engineering design modifications would be needed for the U.S. Arctic oceans of the Chukchi and Beaufort Seas. The Hibernia facility was designed to operate as a bottom-founded structure to operate in 263′ of water, and to resist iceberg impact loads of 500 MN (no damage) for the 500-year event and 1,300 MN for the 10,000-year event (survive with no loss of life or pollution to the environment).

250′).* Floating production systems,†, [59] subsea wellhead production systems, or fixed jack-up production platforms‡, [60] should not be used, unless proven environmentally preferable and safer and the improved technology alternative is subject to third-party expert review and certification.

- Production facilities should be designed and constructed in accordance with Arctic engineering practices and should be able to withstand the worst-case geological hazards, Arctic temperatures, wind, wave, and ice hazards that may be encountered.
- The construction of offshore facilities should be avoided to the maximum extent practicable through the use of directional drilling from the shore or from existing islands, where technically feasible.
- Offshore pipelines should be required as the preferred oil transportation method to move oil safely to market. No tanker transportation of crude oil should be allowed during development due to the high risk of tanker transit resulting in a collision or grounding in ice conditions. There are also economic benefits associated with using existing infrastructure such as the Trans-Alaska Pipeline and the Valdez Marine Terminal to transport oil to market.
- These limitations should be met unless another alternative is proven environmentally preferable and safer and the improved technology alternative is subject to third-party expert review and certification.

Rationale: Bottom-founded structures or gravel islands, connected to the shoreline by pipelines buried below the ice gouge and scour depth, have been proven to be the safest current design for Arctic offshore operations. As footnoted in the recommended production facility and transportation standards, on the previous page, existing offshore production facilities in Arctic waters are using gravel islands to withstand ice and other Arctic environmental factors. Directional drilling of offshore wells from onshore locations or from existing offshore islands, where technically feasible, reduces impact to the offshore environment.

Other facility and transportation options may be developed and considered, however, consideration of alternatives should be benchmarked against proven Arctic facility and transportation designs to ensure that any new alternative is environmentally preferable and safer to known proven designs.

Interior Department regulations at 30 CFR § 250 do not specify proven Arctic facility or transportation designs and set very few facility or transportation design standards for the Arctic. For example, 30 CFR § 250.800(a), for oil and gas production safety systems, requires that an operator only "consider" Arctic conditions in the design: "Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety and protection of the human, marine, and coastal environments. Production safety systems operated in

* Gravel island (in water depths up to 60′) or bottom founded structural design (in water depths up to 250′), covers the water depths of the current U.S. Chukchi and Beaufort sea leases.

† Interior's Consulting Expert (IMV) recommends against the use of floating production structures in the U.S. Beaufort and Chukchi Seas. IMV concluded: "Floating production systems for the Beaufort Sea, Chukchi Sea and North Bering Sea are not considered to be technically feasible, even with continuous ice management. No floating production structures could be economically designed to stay on station with multiyear ice loads found in the Beaufort and Chukchi Seas, and possibly northern Bering Sea depending on local ice conditions. Floating systems may have some merit in southern Alaskan OCS areas, however."

‡ Interior's Consulting Expert (IMV) recommends against the use of fixed jack-up production platforms in the U.S. Beaufort and Chukchi Seas for year-round production systems. IMV concluded: "Current design practice and understanding of jacket design make their application unsuitable for the Beaufort and Chukchi Seas" and that fixed jack-up production platforms have only been proven for subarctic areas such as Cook Inlet. "Infrastructure used to develop Cook Inlet's offshore oil resources consist of fixed jacket offshore platforms connected to land based storage and distribution facilities via subsea pipelines. These structures are subject to first-year ice conditions ranging from 20 to 79" (0.5 to 2.0 m) thick."

subfreezing climates shall utilize equipment and procedures selected with consideration of floating ice, icing, and other extreme environmental conditions that may occur in the area."

Interior Department regulations at 30 CFR § 250, Subpart I, for Offshore Platforms and Structures, do not include specific Arctic design standards. For example 30 CFR § 250.901 lists requirements for offshore structures, including design requirements for hurricanes common in the Gulf of Mexico; however, this list does not include Arctic design standards. 30 CFR § 250.909 provides for a platform verification program to assess new or unique designs of fixed or bottom-founded offshore production facilities, or "platforms"; however, this program does not provide any Arctic-specific criteria or assessment requirements. The current regulations are drafted to mainly address offshore platforms in temperate water.

The only specific Arctic design standard for an offshore platform is found at 30 CFR § 250.906, which says the operator must take into account ice scour data when obtaining approval for the offshore facility location.

A recent technical paper published by ExxonMobil Research Co. summarizes the problem: "The oil and gas industry has relatively little experience with exploring and developing hydrocarbon resources in cold, ice-covered offshore areas. **This is mainly because conventional offshore technologies developed by the industry over the years for the ice-free seas have a limited application in the Arctic seas.** [emphasis added]."[61]

The Arctic environment poses additional challenges to offshore facilities, including: marine icing on exposed surfaces, structural vibrations from ice impact, ice forces exerting considerable crushing forces on offshore structures, and topsides needing to be winterized to protect equipment from freezing. Steel metallurgy is of special interest to Arctic engineers because steel must remain ductile at extreme low temperatures; therefore, use of higher-quality low-temperature steel is needed in Arctic facility design.

Facilities must be designed for new first-year ice, multiyear floe or iceberg impacts, continuous ice interaction, ice ridge interaction, ice encroachment or ice rubble buildup.[62] Frequent storms tend to disturb the first-year ice before it attains sufficient thickness to resist displacement. As a result, the multiyear floes can travel great distances and attain relatively high speeds in open water. Potential concerns for oil and gas facilities include impact loads on fixed structures such as man-made islands and platforms, displacement of floating structures such as drillships and ice gouging in the vicinity of subsea pipelines.[63]

Design loads for the Beaufort and Chukchi seas are 10-20 times the design load of large temperate-water Gulf of Mexico platforms built for hurricanes and rough seas or subarctic Cook Inlet platforms built for ice and storm events. For example, Union Oil calculated[*] the horizontal design load for a Gulf of Mexico offshore platform to withstand a 73' wave to be 5,730 tons; whereas a shallow Beaufort Sea gravel island must be designed to handle a horizontal design load of 54,000 tons to prevent damage from first-year sheet ice; a 120'-deep Beaufort Sea bottom-founded steel cone structure would need to be designed to handle a horizontal design load of 79,000-87,000 tons to prevent damage from multiyear ice floes and ice ridges; and a 150'-deep Chukchi Sea bottom-founded steel cone structure would need to be designed to handle a horizontal design load of 86,500-90,500 tons to prevent damage from multiyear ice floes and ice ridges.[64] By comparison, a Cook Inlet subarctic offshore platform (such as the Monopod or Grayling) operating in first-year sheet ice would need to be designed to handle a horizontal design load of 3,700-6,900 tons to prevent ice damage.

In 2008 the Interior Department funded a study of Arctic design concepts for both exploration and production

* Union reported that its calculations were conservative, but showed the relative magnitude in design requirements between offshore temperate, subarctic and Arctic production facility structures.

facilities and drilling rigs in the Beaufort and Chukchi seas that was completed by IMV Projects Atlantic Inc.[65] The Interior Department's Arctic Offshore Technology Assessment concluded that bottom-founded structures are safe and economic for the Arctic up to about 250′ deep and gravel islands to about 60′ deep, and that alternative designs in deeper waters will need to be developed (as summarized in Table A1.1, an excerpt from the IMV study). Other facility designs examined could not withstand the formidable crushing ice forces that are present year-round. Consistent with the Interior Department's findings, and until other safer alternatives are developed, production facilities should be limited to these known and proven facility designs. For the Beaufort Sea, Interior's consultant (IMV) recommended bottom-founded and fixed type structures (such as gravity-based structures [GBSs], mobile bottom-founded units, gravel islands and ice islands) for production facilities. For the Chukchi Sea, IMV recommended bottom-founded and fixed type structures (such as GBSs) or production facilities. (See Table A1.1.)

While Alaska's subarctic area of Cook Inlet has used fixed offshore year-round jacket production structures, with ice reinforced legs, IMV evaluated and rejected the option of using a fixed offshore jacket production structure in the Chukchi or Beaufort seas, due to the severity of the year-round ice conditions.

In water less than 60′ deep, gravel islands can be constructed and submersible drilling systems may be used, such as the Concrete Island Drilling Structure, or CIDS, that is operating in Russian waters. In water 60-100′-deep, caisson-retained systems may be constructed to build an island using large box structures called caissons as retaining walls[*] and submersible drilling systems may be used.[67] In water depths greater than 100′, large conical steel or concrete structures will most likely be required, with base structures several hundred feet in diameter to distribute the weight load across the seabed.[68]

As of 2013, there is only one U.S. Arctic OCS production facility operating in the Beaufort Sea (Northstar Production Facility). There are no OCS production facilities installed in the Chukchi Sea. BP's Northstar facility is installed on a 400′-by-400′ man-made gravel island in the Beaufort Sea, about six miles from shore in approximately 40′ of water, and is connected to the shoreline with a buried subsea pipeline.[69] Northstar produces from both state and federal (OCS) waters. There may be some additional locations in the Beaufort Sea, where OCS oil and gas resources exist in commercial quantities in shallow water that would provide an opportunity to build production facilities on a gravel island, although most OCS production facilities in the deeper waters of the Beaufort Sea will need to be developed from permanently installed bottom founded structures. Gravel islands will not be an option for the Chukchi Sea, where oil and gas leasing is limited to water depths that exceed the technical limit for a gravel island.

There are no bottom-founded structures installed in the Chukchi and Beaufort Seas at this time; substantial engineering work is still needed to develop an optimal design for the Chukchi and Beaufort seas and will require close regulatory scrutiny and expert review.

In 2010, the ISO developed an international standard for Arctic Offshore Structures called ISO 19906. ISO 19906 Arctic Offshore Structures Standard considers ice-loading on the structure and includes design standards for man-made islands; fixed steel structures; fixed concrete structures; floating structures; subsea production systems; topsides; ice engineering for operations; and safety and environmental issues in ice.[70] The ISO 19906 standard specifies requirements and provides recommendations and guidance for the design, construction, transportation, installation, and removal of offshore structures, related to petroleum and natural gas activities in Arctic and cold regions. The standard does not cover: MODUs; mechanical, process and electrical equipment;

* Two caisson-retained islands have been built in the Canadian Beaufort Sea at Tarsuit and Kadluk.

Table A1.1[66]

Arctic and Cold Region Exploration and Development Options

Region	U.S. Beaufort Sea	Chukchi Sea	Bering Sea	Cook Inlet	Canadian Beaufort Sea	Canadian High North	Canadian East Coast	Offshore West Greenland	Barents Sea	Kara Sea (Gulf of Ob)	Pechora Sea	Baltic Sea	Sakhalin Island
Bottom-Founded and Fixed-Type Structures													
Gravity Based Structure	X	X	X		X		X			X	X		X
Mobile Bottom-Founded	X				X					X			
Barge			X		X								
Jacket/Monopod			X	X			X						
Jack-Up			X	X			X						X
Gravel Island	X				X								
Caisson Retained Island					X								X
Ice Island	X				X								
Floating Structures													
Floating Production Storage and Offloading/ Floating Storage and Offloading Units			X				X	X					
Spar							X		X				
Tension-Leg Platform							X		X				X
Semisubmersible			X	X			X	X					X
Drillship	X	X		X	X		X	X					
Floating Ice Pad						X							
Export and Infrastructure													
Offloading Buoy/Terminal			X				X				X		X
Export Terminal		X	X			X	X		X		X	X	X
Pipeline	X	X	X		X	X	X		X			X	X
Subsea/Flow Lines	X	X	X		X	X	X	X	X				X

Source: IMV Projects Atlantic Inc.

and operation, maintenance, service-life inspector or repair.[71] Important environmental parameters examined in the standard include: ice type, size and thickness, water depth, sea state, wind, currents, season length, and temperature.

Engineering assessment was completed to calibrate the ISO 19906 standard to a range of Arctic areas. A specific study completed for the U.S. Beaufort Sea and Chukchi Sea required the ISO 19906 to plan for multiyear ice floes and ice ridges exceeding 100′ that are present, in addition to first-year ice features that are much thicker, more consolidated, and stronger due to the extrusion of salt through brine drainage.[72]

Arctic OCS drilling rig performance standards for exploration drilling

Proposal: The requirement for Arctic OCS drilling rig performance standards for exploration drilling should be added to the Interior Department's regulations at 30 CFR § 250, and require that the rig:

- Meet Polar Class[73] or equivalent[74] standards.
- Hold a valid classification society certification from a recognized classification society throughout the duration of the operation that verifies the drilling rig is appropriate for the site, intended use and season of operation.
- Be constructed of steel that will not become brittle in low temperatures and have propulsion systems equipped to operate in ice conditions that will be encountered.[75]
- Work areas be fully or partially enclosed to protect workers and equipment from freezing conditions.[76]
- Be inspected by an independent third-party expert prior to use. The expert should:
    - Be a technical classification society or a licensed professional engineering inspection or certification firm.
    - Not be the original equipment manufacturer.[*, 77]
    - Be reputable, hold appropriate licenses to perform the verification in the appropriate jurisdiction, carry industry-standard levels of professional liability insurance, and have no record of violations of applicable laws.
    - Ensure drilling rigs are in good condition and are suitable for operation in the Arctic.
    - Examine the conditions the rig may encounter during the planned drilling period, as well as during any unplanned well control operations that may require the rig to remain at the drill site.
    - Verify that the rig has not been compromised or damaged from previous service and that it has no outstanding deficiencies.
    - Complete the third-party audit with adequate time for an operator to make appropriate changes or improvements or locate an alternative support vessel prior to the drilling season.
    - Issue a report directly to Interior certifying that the drilling rig meets all regulatory requirements and is capable of safely operating in Arctic conditions, prior to approval of any Application for a Permit to Drill.

Rationale: To date, there have been 30 Alaska OCS Beaufort Sea exploration wells drilled.[†] Beaufort Sea OCS exploration wells were drilled with a number of different drilling rigs. All drilling rigs were purpose-built for Arctic drilling and were drilled from the following:

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* 30 CFR § 250.416(f) where the Interior Department sets limits on third-party auditors for blowout preventers, similar limits were used here for drilling rigs.

† Table A1.2 and the list do not include Shell's 2012 attempt to drill a well in the Beaufort Sea using the Kulluk, since only a top-hole section was drilled, and the well was not drilled to the hydrocarbon zone.

- Eleven wells from gravel islands in water depths 18′-49′.
- One well from a spray ice island in water depth 25′.
- Four wells from the CIDS in water depths 35′-50′.
- Five wells from the Single Steel Drilling Caisson, or SSDC, in water depths 55-66′.
- Four wells from the Canmar Explorer II drillship in water depths 103′-166′.
- Five wells from the Kulluk in water depths 96′-167′.

All Beaufort Sea OCS exploration wells drilled in more than 50′ of water were drilled from Arctic Class drillships. No wells have been drilled in the Beaufort Sea OCS using temperate-water drillships that were not purpose-built for the Arctic. (See Table A1.2.)

Historically, there have been five Alaska Chukchi Sea exploration wells, all drilled using the Canmar Explorer III drillship.[*] No wells have been drilled in the Chukchi Sea OCS using temperate-water drillships that were not purpose-built for the Arctic. (See Table A1.3.)

More than 150 wells were drilled in the U.S. and Canadian Arctic waters of the Chukchi and Beaufort seas during the 1970s and the early 1990s. Most of these wells were drilled in water depths of less than 72′ with bottom-founded drilling rigs. In some cases drilling rigs were placed on gravel islands and ice islands, and in other cases, specialty purpose-built Arctic bottom-founded drilling rigs like the SSDC, Molikpaq, and CIDS were used. Some of the wells (53) were drilled from floating vessels that were specialty purpose-built Arctic drilling rigs such as the Canmar/Dome drillships and the Kulluk.[82] The Canmar/Dome drillships and the Kulluk are ice- strengthened drillships. The Kulluk is currently owned by Shell, and is undergoing upgrades for potential use in the U.S. Arctic.

History demonstrates that Arctic wells drilled with specialty purpose-built Arctic or Polar Class drilling rigs or from gravel and ice islands built to withstand ice forces pose lower risks.[83] Ice can impose extreme loads that are orders of magnitude higher than extreme loads from waves, wind, and current combined.[84] While ice loads can be reduced by ice management, using supporting ice-breaking tugs, the rig itself must be equipped to resist ice loads that could result in catastrophic failure. Purpose-built drilling units dedicated to drilling in Arctic waters typically have a cylindrically shaped structure at the ice/waterline to break ice, ice-resistant hulls, sophisticated mooring systems, and seakeeping ability suited for Arctic conditions.[85]

Conventional drilling rigs, designed for temperate waters and some limited use in subarctic regions have not been used to drill U.S. Arctic exploration wells, with the exception of Shell's most recent use of the Discoverer drillship.[†] The Discoverer was used in 2012 to drill a 1400′ top-hole section of a well in the Chukchi Sea. There was tremendous concern from the local communities and public about the first use of a drillship in the U.S. Arctic that was not purpose-built for Arctic drilling.

In 2012 ConocoPhillips proposed, but this year withdrew, the use of a heavy weather North Sea jack-up drilling rig to drill an exploration well in the Chukchi Sea.[86] Prior to 2008, ConocoPhillips had considered a new build

* Table A1.3 does not include Shell's 2012 attempt to drill a well in the Chukchi Sea using the Discoverer, a drillship that was not purpose-built for Arctic use, since only a top-hole section was drilled at the well was not drilled to the hydrocarbon zone.

† The Discoverer is one of the oldest drillships currently operating in the world. Built in 1965, it was originally designed to be a log carrier. It was converted to a temperate water drillship in the 1970s. Shell reports that the drillship has been improved to an Ice-05 standard with the addition of an "ice belt" around the vessel hull, this only increases the vessel's rating to operate in 0.5 meters (1.6′) of ice. These ice conditions could be exceeded in late fall, early winter conditions in the Chukchi Sea. Historically, ice exceeding these conditions has also been present in the proposed drilling area.

Table A1.2[78]

Alaska OCS Region Beaufort Sea Exploration Well History Through 2011

Lease OCS Y-	Operator	Prospect	Latitude (NAD 27)	Longitude (NAD 27)	Spud	End	Water Depth	Drilling Unit
180	Shell Oil Co.	Seal	70 29' 31.77"N	148 41' 34.68"W	2/22/1985	7/21/1985	39'	P.N.J.V. Rig #1 Seal Gravel Island
181	Shell Western E&P Inc.	Seal	70 29' 31.44"N	148 41' 35.80"W	2/4/1984	6/30/1984	39'	P.N.J.V. Rig #1 Seal Gravel Island
191	Exxon Corp.	Beechey Point	70 23' 11.79"N	147 53' 27.98"W	11/1/1981	3/31/1982	18'	Nabors 27-E, BF-37 Gravel Island
191	Exxon Corp.	Beechey Point	70 23' 11.79"N	147 53' 28.71"W	12/27/1981	3/15/1982	18'	Nabors 27-E, BF-37 Gravel Island
195	Shell Oil Co.	Tern	70 16' 46.02"N	147 29' 45.61"W	5/28/1982	9/18/1982	21'	Brinkerhoff #84, Tern Gravel Island
196	Shell Oil Co.	Tern	70 16' 46.33"N	147 29' 44.90"W	10/16/1982	3/3/1983	21'	Brinkerhoff #84, Tern Gravel Island
197	Shell Western E&P Inc.	Tern	70 16' 46.33"N	147 29' 44.89"W	2/10/1987	5/10/1987	22'	Pool Arctic #5, Tern Gravel Island
267	Arco Alaska Inc.	Fireweed	71 05' 16.723"N	152 36' 11.479"W	10/19/1990	12/25/1990	50'	Single Steel Drilling Caisson
280	Exxon Corp.	Antares	71 02' 10.05"N	152 43' 25.28"W	11/1/1984	1/18/1985	49'	Concrete Island Drilling Structure
280	Exxon Co. USA	Antares	71 02' 10.00"N	152 43' 25.46"W	1/19/1985	4/12/1985	49'	Concrete Island Drilling Structure
302	Amoco	Mars	70 50' 34.83"N	152 04' 17.98"W	3/12/1986	4/27/1986	25'	Spray Ice Island
334	Sohio Alaska Petroleum	Mukluk	70 41' 00.04"N	150 55' 11.89"W	11/1/1983	1/24/1984	48'	United Rig # 2, Mukluk Gravel Island
338	Tenneco	Phoenix	70 43' 01.99"N	150 25' 40.15"W	9/23/1986	12/19/1986	60'	Single Steel Drilling Caisson
370	Shell Oil Co.	Harvard	70 35' 05.4"N	149 05' 48.8"W	9/2/1985	1/25/1986	49'	Pan American Alaska Rig #5, Sandpiper Gravel Island
371	Amoco	Sandpiper (Harvard)	70 35' 05.45"N	149 05' 48.40"W	2/8/1986	7/12/1986	49'	Pan American Alaska Rig #5, Sandpiper Gravel Island
742	Arco Alaska Inc.	Cabot	71 19' 25.44"N	155 12' 56.48"W	11/1/1991	2/26/1992	55'	Single Steel Drilling Caisson
804	Exxon Co. USA	Orion	70 57' 22.3"N	152 03' 46.6"W	11/10/1985	12/15/1985	50'	Glomar Beaufort Sea #1 Concrete Island Drilling Structure
849	Union Oil Co.	Hammerhead	70 21' 52.6"N	146 01' 27.9"W	8/10/1985	9/24/1985	103'	Canmar Explorer II
849	Union Oil Co.	Hammerhead	70 22' 41.79"N	146 01' 52.41"W	9/27/1986	10/11/1986	107'	Explorer II Drillship
865	Arco Alaska Inc.	Kuvlum	70 18' 36"N	145 32' 18.2"W	7/28/1993	8/30/1993	96'	Kulluk
866	Arco Alaska Inc.	Kuvlum	70 18' 57.38"N	145 25' 10.97"W	8/22/1992	10/14/1992	110'	Kulluk
866	Arco Alaska Inc.	Kuvlum	70 19' 36.78"N	145 24' 14.67"W	9/7/1993	10/5/1993	107'	Canmar Kulluk
871	Shell Western E&P Inc.	Corona	70 18' 52.6"N	144 45' 32.9"W	7/28/1986	9/18/1986	116'	Canmar Explorer II
917	Amoco Production Co.	Belcher	70 16' 31.16"N	141 30' 46.49"W	9/5/1988	8/29/1989	167'	Kulluk
943	Tenneco	Aurora	70 06' 33.02"N	142 47' 05.88"W	11/2/1987	8/30/1988	66'	Single Steel Drilling Caisson
1092	Amoco Production Co.	Galahad	70 33' 38.68"N	144 57' 35.75"W	9/14/1991	10/13/1991	166'	Canmar Explorer II
1578	Encana Oil & Gas (USA) Inc.	McCovey	70 31' 37.9"N	148 10' 48.2" W	12/6/2002	1/27/2003	35'	Single Steel Drilling Caisson/Mat
1597	Arco Alaska Inc.	Wild Weasel	70 13' 22.41"N	145 29' 57.11"W	10/13/1993	11/9/1993	87'	Canmar Kulluk
1650	British Petroleum Exploration (Alaska)	Liberty	70 16' 45.113"N	147 29' 47.145"W	2/7/1997	3/30/1997	21'	Pan American Alaska #4 Tern Gravel/Ice Island
1663	Arco Alaska Inc.	Warthog	70 02' 34" N (NAD 83)	144 55' 02 W (NAD 83)	11/1/1997	12/5/1997	35'	Concrete Island Drilling Structure

Source: Bureau of Ocean Energy Management

Table A1.3[80]

Alaska OCS Region Chukchi Sea Exploration Well History Through 2011

Lease OCS Y-	Operator	Prospect	Latitude (NAD 27)	Longitude (NAD 27)	Spud	End	Water Depth	Drilling Unit
996	Chevron USA Inc.	Diamond	71 19' 48.34"N	161 40' 48.01"W	9/7/1991	10/5/1991	152'	Explorer III Drillship
1275	Shell Western E&P Inc.	Popcorn	71 51' 16.385"N	165 48' 24.893"W	10/14/1989	9/23/1990	143'	Explorer III Drillship
1320	Shell Western E&P Inc.	Crackerjack	71 25' 7.665"N	165 32" 29.253"W	9/23/1990	8/31/1991	137'	Explorer III Drillship
1413	Shell Western E&P Inc.	Burger	71 15' 04.995"N	163 11' 40.499"W	9/22/1989	8/22/1990	149'	Explorer III Drillship
1482	Shell Western E&P Inc.	Klondike	70 42' 39.171"N	165 14' 59.107"W	7/9/1989	9/15/1989	141'	Explorer III Drillship

Source: Bureau of Ocean Energy Management

ice-class drillship to drill in the Chukchi Sea, but instead ConocoPhillips considered the use of a generic three-legged truss jack-up drilling rig that was not purpose-built for Arctic operation.[87] ConocoPhillips acknowledged that use of a jack-up increased risk due to ice floe impacts to the jack-up legs. ConocoPhillips' 2012 engineering analysis concluded that an ice floe with a mass of 250 tonnes, roughly equivalent to a 6.5′-thick and 40′-long ice flow could damage the diagonal brace of the jack-up leg. Ice floes larger than 250 tonnes have been documented in the Chukchi, as explained in Arctic OCS Equipment Design and Operating Performance Standards Based on Worst-Case Historic Conditions section above.[88]

To prevent future drilling rigs from being proposed and approved that are not purpose-built for Arctic drilling, Arctic OCS Drilling Rig Performance Standards need to be set in the Interior Department's regulations. While some purpose-built Arctic drilling rigs have been moved to another country for long-term service or have been taken out of service, new rigs are available, under construction, or could be constructed if the Interior Department's minimum Arctic drilling rig performance standards were codified clarifying the minimum requirement. There will not be an economic incentive to build Arctic drilling rigs if operators are allowed to use less robust rigs as an alternative.

In April 2012, Lloyds of London issued a report stating that there is "a shortage of Arctic-class mobile rigs capable of drilling relief wells in the event of a spill." Lloyds' report highlighted the increased risk factors for Arctic operation, including: ice damage to hull; ice damage to propulsion systems; icing; ice fog; delay or lack of salvage exacerbated by remoteness; lack of safe ports; and communication systems challenges due to remoteness.[89]

A current analysis of rig inventory shows that there are Arctic rigs either in the current drilling fleet or under construction that could be available with planning. Additionally, with advanced planning, extra Arctic rigs could be constructed. GustoMSC,[90] Inocean[91] and Transocean report willingness to construct Arctic drillships to meet the growing demand.[92]

New drillships run approximately $1 billion and can take 3-4 years to construct, depending on shipyard availability. Costs for true Arctic-class drillships can range from $450,000-$500,000 per day, not including mobilization or demobilization costs,[93] substantially more than temperate-water drillships that may range on the order of a few hundred thousand per day. There is concern that temperate water drilling rigs may be used in the

Arctic merely to save cost, regardless of environmental impact, rather than contract the more expensive rig or build an Arctic-class purpose-built rig.

There is often confusion about which Arctic drilling rigs are available, which are under contract working in other areas, and which have been taken out of service. A summary is provided below:

- **Concrete Island Drilling System:** Built in 1984 to Global Marine's CIDS standard, this MODU is rated to drill in up to 55′ of water and to a drilling depth of 20,000′.[94] CIDS is currently working for Exxon in Sakhalin, Russia, on a long-term project. The CIDS is rated to drill in up to 2 meters of ice (6.6′) and in ice concentrations of up to 10/10ths (100%).[95]
- **Molikpaq:** The Molikpaq structure is an octagonal-shaped steel caisson bottom-founded structure built for operation in year-round Arctic conditions of the Beaufort Sea in water depths up to 65′, built by Gulf Canada to drill exploration wells in the Canadian Beaufort Sea.[96] Built in 1984 to an Arctic Caisson Standard, the Molikpaq is rated to drill in up to 130′ of water and to a drilling depth of 19,680′.[97] It is rated to drill in up to 10 m of ice (32.8′) and in ice concentrations of up to 10/10ths (100%).[98]

  The Molikpaq is currently working for Sakhalin Energy in Sakhalin, Russia, on a long-term project and was converted into a production platform (called Sakhalin-2, and later renamed to the Pitun Astokh-A production platform). Sakhalin Energy added a wave-deflector shield, earthquake strengthening, and an additional 50.5′ of structure to increase the Molikpaq's ability to operate in a water depth of 100′ at 7.5 miles offshore.[99]
- **Canmar Explorer II and III:** The Canmar Explorer drillships were built to Pelican-class specifications and were the first dynamically positioned drillships to operate in the Arctic. The Canmar Explorer II was renamed the Northern Explorer II and was classified as a Super Ice drillship but is now retired.[100] The Canmar III was upgraded in 2009 and renamed the Neptune Explorer, and then later renamed the Jasper Explorer.[101] The Jasper Explorer is rated to drill in 5,000′ of water to a drilling depth of 25,000′[102] and is a DNV Classed Ice-Strengthened A Class Vessel; it is currently drilling in Africa.[103]
- **Steel Drilling Caisson, or SDC:** Built in 1982, the SDC MODU is rated to drill in up to 80′ of water and drill to depths of 25,000′. This rig used to be called the Single Steel Drilling Caisson. The SDC is an Arctic-class rig designed by Canadian Marine Drilling Ltd., and is currently stacked in Canada.[104] SolstenXP is the current Management Contractor for Seatankers Management Co. Ltd. Solsten XP reports that the SDC is: "the only remaining Arctic submersible available for drilling exploration wells in the Beaufort Sea. The SDC was recommissioned in August 2002 by SolstenXP and utilized for drilling of the McCovey exploration well during the 2002/2003 Beaufort Sea winter drilling season."[105] The SDC is rated to drill in up to 32.8′ and in ice concentrations of up to 10/10[ths]ths (100%).[106] The SDC is reported to be stacked in Canada and ready to work.[107]
- **Kulluk:** The Kulluk is a 24-faceted, conically shaped double-hull MODU that meets an Arctic Class IV classification (equivalent to Polar Class 4). This MODU was built in 1982 and has operated in Alaska and Canada's Beaufort Sea. The Kulluk is rated to drill in 400′ of water and to a depth of 20,000′.[108] The Kulluk is currently owned by Shell. The Interior Department rates the Kulluk as a vessel that is "able to operate until early December (at the latest) with intensive ice management support."[109]

Therefore, of the list of rigs that have successfully drilled in the U.S. Arctic before, the rigs that are potentially available include the Jasper Explorer, SDC, and Kulluk. While not an exhaustive list, there are other potential purpose-built Arctic drill rigs either built, under construction, or in the design phase that could be considered:

- **NanuQ 5000 Arctic drillship:** GustoMSC is designing a new-concept NanuQ 5000 Arctic drillship targeted for operations in offshore Alaska, Canada, Greenland, Iceland, Norway, and Russia.[110] This ship is being designed for shallow Arctic waters. GustoMSC reports that "the hull design is optimized for performance under ice conditions to enable year-round drilling with ice management. The ice-classed hull, on a selective basis, features the highest ice-class notation from the leading classification societies."[111] Drilling and marine systems are fully winterized.
- **INO-80 Arctic drillship:** Inocean, a Norwegian marine design and engineering company, is developing an Arctic drillship called the INO-80 to meet a Polar Class 4 standard.[112]
- **JBF Arctic MODU:** The JBF Arctic MODU design is underway to develop a rig capable of drilling year-round in Arctic conditions using one draft optimized for open water conditions and a deeper draft for ice covered waters.[113]
- **DrillMAX ICE drillship:** The DrillMAX ICE drillship was constructed for Stena Drilling at the Samsung, South Korea, Shipyard. The estimated cost reported in 2013 was $1.15 billion.[114] The ship is currently under contract by Shell and is operating in South America. The rig is designed to operate in water up to 10,000′ and drill to 35,000′, and will be equipped with dynamic positioning systems.[115] It has been tested in ice up to 7.2′ thick.[116] The drillship received a Polar Class 5 (equivalent to Ice 10 Class) and the drilling rig and superstructure have been winterized.[117]
- **Deep Venture:** The Deep Venture is a dynamically positioned drillship, built in Finland in 1981 and upgraded in 1998 and 2006. Originally named the Valentin Shashin, the drillship was originally built for the USSR Ministry under the USSR Register of Shipping class notation: KM ULI FA2 Drillship – Super Ice Class.[118] It is capable of drilling in 4,200′ of water and up to 20,000′ deep.[119] The Deep Venture is currently drilling for VietSovPetro in Vietnam.[120]
- **Noble Muravlenko:** The Noble Muravlenko is a dynamically positioned drillship, built in Finland in 1982 and previously named the Viktor Muravlenko. It is a DNV Ice Class, Pelican Class drillship, the same as the Canmar Explorer design. It is capable of drilling in 4,900′ of water and up to 20,000′ deep.[121] The Noble Muravlenko is currently drilling for Petrobras in Brazil.[122]
- **Polar Pioneer Semisubmersible:** The Polar Pioneer was built in 1985 by Hitachi Zosen to a HITACHI ARCTIC standard.[123] The rig is capable of drilling to 25,000′ deep in up to 1,640′ of water. The Polar Pioneer is currently drilling (2012) for BP in Norway's North Sea, and is reportedly under contract until 2014.
- **Peregrine I:** The Peregrine I is a dynamically positioned drillship built in Finland in 1981 and upgraded in 1998 and 2006, it was originally named the Mikhail Mirchink. It is a DNV Ice Class, Pelican Class drillship, the same as the Canmar Explorer design. It is capable of drilling in 5,200′ of water and up to 25,000′.[124]
- **Ice-Jack-Up Rig:** In 2012, ConocoPhillips announced plans to build a "first-of-its-kind ice-worthy jack-up rig" to drill in Alaska's Chukchi Sea.[125] Keppel Offshore & Marine Technology Center has been hired to complete the design. ConocoPhillips called off plans for its construction after postponing Arctic drilling in 2013.
- **Bully 1 and Bully 2 drillship:** GustoMSC designed two Arctic-class drillships for Frontier Drilling (now Noble Drilling) called the Bully 1 and Bully 2, for Shell.[126] The design was based on drilling during the extended summer season in the Arctic; the hull and marine systems are Arctic class. The rig can drill in up to 10,000′ of water.[127] The rig is rated by DNV to be ICE-05 class, meaning it can withstand ice up to 0.5 m (1.6′), and operate in managed-first-year ice (broken by a support icebreaker) to less than 0.5 m thick. The vessel features an ice-classed hull with an icebreaker bow. In December 2011, the *Oil and Gas Journal* reported that

Shell moved the Bully 1 to the Gulf of Mexico to drill development wells for Shell's deepwater Mars B Olympus project.[128] Noble reports that it has a contract with Shell to drill with the Bully 2 until 2022 in Brazil.[129]

Currently, 30 CFR § 250.417 for MODUs requires the operator to demonstrate that its rig is fit for service, but there are no specific Arctic criteria established for drilling rigs used for exploration drilling. 30 CFR § 250.417 also requires a third-party audit in frontier areas; however, the Interior Department does not define the term frontier in regulations. Interior has not historically required third-party audits for Beaufort or Chukchi MODUs; this is likely because Interior's third-party audit regulations (30 CFR § 250.915-918) apply to platforms and structures, not MODUs that are used for Arctic exploration. Pew has requested clarification of this requirement from the Interior Department and has requested information on whether a 30 CFR § 250.417 analysis was completed by Shell for its 2012 Arctic Exploration Program and whether a third-party audit was completed. Pollution prevention regulations at 30 CFR § 250.300 do not include anything specific for MODUs or Arctic application.

Nearshore areas of the Chukchi and Beaufort seas have landfast ice; by the end of winter, landfast ice is typically 5-7′ thick, extending out to about 60′ of water depth.[130] There are nearshore leases in the Beaufort Sea, but not in the Chukchi Sea. Chukchi Sea leases start at 25 miles offshore.

In the nearshore Beaufort Sea area, there are two potential drilling seasons: (1) during open water in summer, and (2) during stabilized ice conditions in winter. In deeper waters of the Beaufort and Chukchi seas, exploration drilling occurs in open water in summer. Historically, ice-resistant, bottom-founded drilling systems have been used in the nearshore areas during the summer season, or ice or gravel reinforced islands were constructed and drilling units were placed atop the islands.

In deeper water, the ice remains mobile throughout most of the year. The amount of thick multiyear ice increases with increasing distance from shore.[131] Depending on water depth, bottom-founded and floating drilling rigs have been used during open water in summer.

Year-round drilling is only possible in deeper water using a bottom-founded production facility (including a drilling rig) or a bottom-founded mobile drilling rig designed for year-round operations in ice. Floating systems only have limited capability to remain on location in ice, depending on their hull construction.

The Arctic Ocean's open water period is relatively short. Storms, ice, and other hazardous conditions can be present even during the open-water period, and well control issues could delay exploratory drilling (planned for the summer season) into challenging fall and winter Arctic conditions.

Exploration drilling rigs need to meet minimum Arctic operating standards to ensure their fitness will not be compromised in any hazardous conditions that may be presented. The situation of most concern is a late season well blowout that requires drilling to continue into late fall-early winter ice, which will require Polar Class rigs. While the plan may be to avoid interaction with the ice by implementing an ice-monitoring and rig-retreat plan, drilling rig retreat will not be an option when a blowout occurs and relief well rig must remain in position to drill a relief well in the weather and ice conditions that may be present.

Once exploration drilling is completed, and a year-round OCS production facility is built, a development drilling rig could be installed on top of that facility to drill the remaining production wells. The production facility would be designed for offshore water depths with ice, and weather conditions expected. The development drilling rig would need to be capable of withstanding the Arctic weather conditions in which it plans to operate (e.g., enclosed and winterized).

In 2008 Interior funded a study of Arctic design concepts for both exploration and production facilities and drilling rigs in the Beaufort and Chukchi seas that was completed by IMV Projects Atlantic Inc.[132] For the Beaufort Sea, IMV recommended bottom-founded and fixed type structures (such as GBSs, mobile bottom-founded units, gravel islands and ice islands), and floating structures such as drillships for exploration operations. For the Chukchi Sea, IMV recommended bottom-founded and fixed type structures (such as GBSs and floating structures such as drillships for exploration operations).

Of importance, IMV did not recommend the use of jack-up drilling rigs for either the Beaufort or Chukchi Sea, limiting the use of jack-up structures as a viable solution only for the subarctic locations of Alaska such as the Bering Sea or Cook Inlet. IMV concluded: "Current design practice and understanding of jacket design make their application unsuitable for the Beaufort and Chukchi Seas."[133] Additionally, a study by an Interior Department contractor in 2011[134] found that no heavy lift ice-classed transportation vessels are currently available to transport a jack-up drilling rig to the Arctic, and that the currently available heavy lift fleet of vessels is 100% foreign flagged and is precluded from transport to Alaska by the Jones Act.

Arctic drillships must be equipped with heating and ventilation systems that can safely and efficiently operate in Arctic temperatures that can drop to minus 20 to minus 40 F in the late fall. This includes anti-icing and deicing equipment, additional enclosed areas for personnel and equipment, and heating systems for enclosed areas, ballast and water tanks, helidecks and exposed walkways.[135] Drillship winterization must also take into account severe icing and exposure of the hull and industrial systems to frozen seas and extreme air temperatures.[136]

Drillships working in Arctic waters, even in the summer months, require icebreaker support for ice management and must be capable of transiting through thick first-year Arctic ice, with the potential to encounter thicker and harder multiyear ice.[137] Arctic drillship design must include a hull shape that minimizes ice loads, prevents ice accumulation in the moonpool areas, prevents ice damage to propulsion systems and can safely transit in ice-infested waters. [138]

Because shallow water dominates most of the current Chukchi and Beaufort seas leases in the United States, station-keeping of a mobile drilling unit (such as a drillship) is a very important design consideration for an Arctic drillship. A turret mooring system is considered the best technology in shallow Arctic waters.[139] Dynamic positioning systems do not provide the positional accuracy required to stay at a drill location in shallow water, taking into consideration ice, wind, wave and current forces that will impact vessel station-keeping. A conventional mooring system could be used; however, these systems do not provide the azimuthing ability to adjust for changes in ice, wind, wave, and current forces, and can add significant downtime.

Canada's National Energy Board, or NEB, Filing Requirements for Offshore Drilling in the Canadian Arctic require[140] an operator to describe in its application how the proposed drilling system is suitable and appropriate for the prevailing and extreme physical environment conditions of the Arctic.

This recommendation is consistent with the International Maritime Organization's, or IMO's, Guidelines for Ships Operating in Polar Waters.

This recommendation is consistent with the National Commission on the BP Deepwater Horizon Oil Spill recommendations, where the commission recommended the safety and environmental management system requirements for drilling to include third-party audits at three- to five-year intervals and certification.[*, 141]

* National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling, Recommendations*, (recommending that the safety and environmental system requirements for drilling be expanded to include third-party audits at three- to five-year intervals and certification).

Arctic OCS vessel performance standards

Proposal: The requirement for Arctic OCS vessel performance standards should be added to Interior's regulations at 30 CFR Part 250, including:

- Vessels should meet the International Maritime Organization Guidelines for Ships Operating in Polar Waters (2010).[142]
- All fuel should be transported in double-hulled vessels,[143, 144, *] supported with sufficient tug assistance to avert a potential collision or grounding.
- Tugs with ice-class capacity for safe ice management, to provide towing support and capability to deploy mooring lines and running anchors in Arctic waters.
- The vessel operating season must end with sufficient lead time to ensure that all drilling rigs and other support equipment can be safely towed and docked for the winter, unless that vessel meets a Polar Class 1 (PC 1) rating for year-round Arctic operation.
- A comprehensive and integrated operational plan that includes schedules for mobilization and demobilization of operations.[145]
- A drilling rig towing plan should be submitted to the Interior Department and the U.S. Coast Guard, and approved prior to towing the rig. The towing plan should:
  - Demonstrate that the operator can safely transporting the drilling rig in the maximum weather conditions that may be encountered.
  - Include a minimum of one tug capable of towing the drilling rig in the worst-case conditions anticipated along the transit route, with a plan for immediate tug assistance if the primary tug is rendered inoperable or additional tug support is required.
  - Include a contingency plan that describes the equipment and procedures for recovering a rig that breaks free of the towing vessel and, define weather and other conditions where it is unsafe to tow the drilling rig and locations for safe harbor that rig will be placed in during these periods along the towing route.
- Towing plans should be required for all fuel supply vessels to ensure a contingency plan is in place to rapidly provide assistance to a disabled fuel supply vessel to avert a collision or grounding, or provide rescue assistance if the vessel becomes trapped in ice.
- Vessels should be equipped with ice load monitoring systems and be capable of managing ice, or travel with support vessels capable of managing ice.[146]
- Redundant propulsion and steering systems should be used to reduce risk and provide backup support.[147]
- Vessels should be inspected by an independent third-party expert. The expert should:
  - Be a technical classification society or a licensed professional engineering inspector or certification firm and qualified in naval architecture and structural analysis, Arctic and marine design and operation.
  - Not be the original equipment manufacturer.148
  - Be reputable, hold appropriate licenses to perform the verification in the appropriate jurisdiction, carry

* Currently Crowley Maritime provides a substantial amount of fuel supply to communities of western Alaska. Crowley has three double-hull fuel barges in operation (the DBL 165-1, the DBL 165-2, and the 180-1). The use of double-hull vessels for fuel transport should be considered an existing best-technology requirement.

industry-standard levels of professional liability insurance, and have no record of violations of applicable laws.

- Ensure vessels are in good condition and are suitable for operation in the Arctic.
- For temporary exploration drilling operations, examine the conditions the vessel may encounter during the planned drilling period, as well as during any unplanned operations that may require the rig to remain at the drill site requiring vessels support for longer periods of time and into difficult ice conditions.
- For permanent production operations, examine the conditions the vessel may encounter while providing support services.
- Verify that the vessel has not been compromised or damaged from previous service and that it has no outstanding deficiencies.
- Complete the third-party audit with adequate time for an operator to make appropriate changes or improvements or locate an alternative support vessel prior to the drilling season.
- Issue a report directly to Interior certifying that the vessel meets all regulatory requirements and is capable of safely operating in Arctic conditions, prior to approval of any Application for a Permit to Drill, or APD.

Rationale: Use of vessels designed, constructed, and proven to be capable of safely navigating in ice-infested waters is best technology for Arctic offshore operations. Vessel transportation in the Arctic, even in the summer season may encounter waves, fog, icing conditions, and ice. These Arctic hazards increase navigational risk. Vessel design and operation must take into account sea ice, icing on the superstructure, strong currents and lack of infrastructure. Remote operation means that vessels may have to perform a broader range of tasks (e.g., firefighting, ice management, oil recovery, towing and supply).[149]

Vessels operating in the Arctic must have thicker, ice-reinforced hulls and propulsion systems that are protected from ice damage,[150, 151] use steels that have properties that prevent crack initiation at low temperatures, and be designed to protect exposed equipment operating in subzero temperatures. Vessels should be equipped with ice load monitoring systems so that action is taken to minimize the likelihood of the vessel sustaining structural damage from interaction with the ice. The American Bureau of Shipping has developed specific guidance for ice load monitoring systems.[152] Vessels should also be capable of managing ice, or travel with support vessels capable of managing ice, and be equipped with deicing systems for navigation and emergency systems.

Fuel transportation, supply, and oil spill response vessels and tugs that are part of an Arctic OCS exploration drilling or production operation must be designed with vessels hulls and specialized systems to function safely in ice and extreme cold. The remote location of Arctic OCS drilling sites, and distance from additional response support, requires oil and gas operators to plan and prepare for self-rescue and emergency response. Double-hulled vessels are the best technology for transportation of fuel in ice-infested waters to provide an additional secondary containment barrier, in the event that the vessel's hull is damaged by ice impact, collision, or grounding. Canada requires that double-hulled vessels be used to transport hydrocarbons in the Canadian Arctic and that the double hull provide at least 30" of separation from the outer vessel shell.[153]

Arctic-class tug capability is needed for safe ice management, to provide towing support and capability to deploy mooring lines and running anchors in Arctic waters. In 2001, an Interior Department contractor found that: "Ice management is identified as a limitation because there is a need to obtain ice-class Anchor Handling Vessel, or AHV, and icebreakers to redirect ice floes. Ice-class AHVs can be provided only by foreign countries since the U.S. icebreaker fleet is limited and already committed to Great Lakes ice-route maintenance and research services."[154]

For rigs without their own independent propulsion systems, tugs of sufficient bollard pull capacity will be required. Anchor handling tugs must be capable of bollard pull requirements of 100 tons or more.[155]

For operations or transit in ice, the bow of the vessel is required to have substantially more hull strength than the stern, unless both bow and stern navigation is anticipated in which case the hull must be strengthened along its entire length.[156] Marine icing can threaten the stability of vessels operating in cold climate regions due to ice accretion (build up) on the superstructure. The vessel's deck and equipment located on the deck must be winterized to prevent freezing and malfunction, and including heating and ventilation systems that have anti-icing and de-icing equipment.* Arctic vessels must also have enclosed areas for personnel and equipment; heated ballast and water tanks, helidecks, and exposed walkways.[157]

Arctic vessel hulls must be capable of withstanding the ice impacts it may encounter, and the crew must be able to predict and react to dynamic ice loading situations. The use of maritime simulators is becoming an increasingly prominent method for planning drilling and construction activities in order to optimize icebreaker assistance and the use of satellite radar to identify ice and tow it away from the operating area to mitigate potential impacts.

ConocoPhillips reports that wave conditions are a factor for transiting to the Chukchi Sea noting that: "Basins south of the Chukchi Sea (Bering Sea) have 100 year wave conditions near those found in the Grand Banks. Conditions in the Bering Sea have resulted in a number of vessels sinking in the past. A MODU would encounter these severe conditions when leaving the Chukchi Sea at the season's end. These conditions resulted in the complete loss of the Dan Prince jack-up in 1980 while under wet tow."[158]

Therefore, rig selection not only must take into consideration a purpose-built Arctic rig, but also the ability to safely transport the rig to and from the drill site.

Canada's Arctic Shipping Pollution Prevention Regulations have specific standards for design, construction, and machinery used on Arctic-class ships.[159]

The American Bureau of Shipping has specific rules for building and strengthening vessels for navigation in ice that adopt the IMO Guidelines for Ships Operating in Polar Waters.[160] Additionally, the American Bureau of Shipping advises that "vessels designed and constructed without addressing the effects of low temperatures may experience increased structural and equipment failures and nonfunctioning systems."[161]

To ensure that robust, fit-for-purpose vessels are selected for use in ice-infested water, an international standard for vessel selection was developed by the IMO, Guidelines for Ships Operating in Polar Waters.[162] As shown in the table below, the IMO-classified vessels based on the operating season and ice conditions that will be encountered. For example, a Polar Class 1 vessel would be suitable for year-round operation in ice-infested waters, whereas, a Polar Class 7 Vessel would only be suitable for summer and autumn operation in thin first-year ice. (See Table 3.)

For example, an ice-classed drillship is substantially heavier than a non-Arctic drillship of similar draft (displacement), both because of the thicker ice-reinforced hull, and because of the additional topside structure required to weatherize the ship's equipment and provide heated working spaces for personnel.[163]

Currently, 30 CFR § 250 and 30 CFR § 550 do not require any specific Arctic OCS vessel performance standards.

* Winterization requires some equipment to be located inside enclosures such as anchor winches, navigation and emergency equipment. Fire extinguishing systems, hydraulic systems and piping must be enclosed and heated.

Pollution prevention regulations at 30 CFR § 250.300 do not include anything specific for MODUs, support vessels, or Arctic application.

30 CFR § 550.220 and 30 CFR § 550.251 require the operator to submit Critical Operations Curtailment Procedures, or COCPs, for exploration, development, and production operations to identify ice conditions, weather, and other constraints under which those operations will be curtailed or shutdown. This regulation, however, assumes that if a vessel's capability is exceed by Arctic ice or weather conditions that it will be safe, or in the best interest of human health or the environment, that operations cease. Yet, there are a number of Arctic vessel support functions that may require an Arctic vessel to continue to operate in severe ice or harsh weather conditions to respond to operational, logistical, health, safety, and environmental issues. For example, Arctic vessels may be called upon to rescue personnel, conduct spill response in ice-infested waters, tow a drilling rig, provide critical supplies, provide support to a relief well rig, or tow emergency equipment such as well capping and containment systems or provide firefighting equipment. For these reasons, it is critical that Arctic OCS vessel performance standards are established to ensure that vessels are capable of providing support in the Arctic conditions and seasons during which the operator plans to conduct activities in including the time required to mobilize equipment to the site, demobilize equipment, and provide emergency services.

In the Review of Shell's 2012 Alaska Offshore Oil and Gas Exploration Program, Interior highlighted the problems encountered at the end of the drilling season while demobilizing equipment. As a result, Interior has recommended that future Arctic plans include a Comprehensive and Integrated Operational Plan that includes schedules for mobilization and demobilization of operations.[164]

In 2001, the Interior Department commissioned a study that concluded: "Logistics and planning are vital because these remote areas [Chukchi and Beaufort Sea] cannot rely on last minute decisions, especially in case of an accident where emergency response units will take a long time to reach a North Slope location. The first line of response in these areas is local communities with limited resources. The United States Coast Guard (USCG bases in Juneau, Kodiak and Anchorage) will take several hours to reach the location by plane and maybe days by sea).* … The main consideration is that the vessels and platforms involved in this project should assess every possible risk and implement a contingency plan with the idea of being self-sufficient and being capable of addressing the risk with no or minimum external support. After identifying areas of weakness, plans should be developed to mitigate the risk."[165]

By comparison, the NEB Filing Requirements for Offshore Drilling in the Canadian Arctic require[166] an operator to describe in its application the ability for support vessels to stay at the drilling location to ensure that drilling and related operations can be carried out safely. Canada's Arctic Shipping Pollution Prevention Regulations have specific standards for design, construction, and machinery used on Arctic-class ships.[167] And, Canada has specific Arctic Ice Regime Shipping System Standards for assisting the ship captains and crew when it is safe to navigate in ice-infested waters, and when a vessel should not be allowed to operate in those conditions because its design is insufficient or unsuitable.[168]

Greenland requires Arctic OCS vessel performance standards. The Government of Greenland, Bureau of Minerals and Petroleum, requires vessels conducting exploration operations off the coast of Greenland to meet the IMO Guidelines for Ships Operating in Polar Waters.[169]

* The North Slope of Alaska has about 2500 miles of shoreline. The USCG has very limited Arctic resources and any response time can very long in remote areas of the Arctic. The USCG 17th District is based in Juneau; no personnel are permanently stationed north of the Arctic Circle. Kodiak, the closest air station, is 950 miles south of the Arctic Ocean.

This recommendation is also consistent with the National Commission on the BP Deepwater Horizon Oil Spill recommendations, where the commission recommended the safety and environmental management system requirements for drilling to include third-party audits at three- to five-year intervals and certification.[*, 170]

Arctic OCS blowout preventer performance standard

The Deepwater Horizon well blowout demonstrated the importance of BOP improvements for the Arctic.[171] Due to the high consequences of an Arctic oil spill, BOP standards should be more stringent in the Arctic including the following improvements.

Arctic BOP third-party verification

Proposal: Interior Department regulations at 30 CFR § 250.416 should be amended to require third-party verification for all Arctic BOPs, including verification of the entire BOP system.

Prior to approval of any APD, the third-party expert should issue a report directly to Interior certifying that each Arctic BOP meets all regulatory requirements and is capable of safely operating in planned Arctic conditions. As part of this review, the expert should:

- Examine any conditions the BOP may encounter during the planned drilling period, as well as during any unplanned well control operations that may require the rig to remain at the drill site.
- Verify that the BOP has not been compromised or damaged from previous service.
- Complete the audit with adequate time for an operator to make appropriate changes or improvements prior to the drilling season.

Rationale: BOPs are critical well control devices. Independent third-party expert verification of BOP system integrity should be expanded beyond the existing requirement to verify blind shear ram function (30 CFR § 250.416(e)) and examine BOP stacks used on floating facilities (30 CFR § 250.416(f)) to include third-party verification for all Arctic BOPs and the entire BOP system.

Arctic BOP repair and recertification

Proposal: Interior Department regulations at 30 CFR § 250 should specify that after major repairs, and at least once every five-year period, BOPs should undergo third-party review and certification before being returned to use. The well should be secured with at least two additional independent well barriers while BOP repair and replacement is underway.

Rationale: BOPs are critical well control devices. BOP age and condition are critical factors in performance and reliability. Aging, worn BOP systems should be taken out of service and repaired or replaced with new BOP systems. There is currently no age limit on BOP systems in Interior's regulations, and as such, there are BOP systems operating in the Arctic that were built in the 1970s and 1980s. It is unclear if these older BOP systems were constructed of low temperature steel that is less susceptible to brittle metal fatigue and stress cracking. It is also unclear whether the BOP body has suffered any corrosion wall loss over time. BOPs stored or used in the Arctic over long periods are subject to significant thermal cycling and corrosive conditions. There is a void of

* National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, *Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling, Recommendations* (recommended that the safety and environmental system requirements for drilling be expanded to include third-party audits at three- to five-year intervals and certification).

published data on the condition of these aging BOP systems. More research should be conducted by the Interior Department on the materials used in existing offshore Arctic BOP systems to ensure that low-temperature steel was used, and that nondestructive testing of the BOP body confirms suitability for continued reliable service in Arctic conditions.

Due to the remote nature of Arctic operations, and the associated difficulties of oil spill response, extra measures should be taken to reduce oil spill risk, including the requirement that BOP systems be recertified after major repairs or at least once every five-year period, before being returned to use.

30 CFR § 250.451(a) requires the operator to correct the problem after a failed BOP test, and retest the affected equipment. However, in the case of major repairs, the regulations do not require independent third-party expert review or certification of BOPs before being returned to use.

30 CFR § 250.451(b) requires the well to be placed in a "safe, controlled condition" during BOP repairs. However, this regulation should be revised to more specifically state that a safe, controlled condition is established by securing the well with at least two additional independent barriers.

Industry experts recommend that recertification of BOPs and other well pressure-control equipment used for drilling, completion, workover and well intervention operations be performed at least every five years.[172] The purpose of a recertification process is to verify and document that condition and properties of BOPs and other well pressure-control equipment are within the specified acceptance criteria as well as specified and recognized codes and standards. The recertification would examine: repair, maintenance, and operational history; owner procedures; and, applicable standards and codes.

BOP remotely operated acoustic activation module

Proposal: Interior Department regulations at 30 CFR § 250 should specify that all BOP systems used in the Arctic OCS should be equipped with a remotely operated acoustic activation module. The remote control for the acoustic activation device should be portable so that it can be transported in an emergency situation and activated after rig activation (e.g., from a lifeboat).

Rationale: Interior Department regulations at 30 CFR § 250.442 specify the requirements for subsea BOP systems for the OCS. 30 CFR § 250.442(f) requires an auto-shear system and a deadman system; however, the acoustic system is an optional secondary control system. The regulation only requires the operator to demonstrate that the acoustic system will function in the proposed environment and conditions if the operator chooses to install it. There is no mandatory requirement to install the system.

BP's Deepwater Horizon well blowout recommendations included the need to "establish minimum levels of redundancy and reliability for BOP systems."[173]

Greenland requires a remotely operated acoustic activation module with portable activation devices.[174]

Arctic BOP testing frequency

Proposal: Interior Department regulations at 30 CFR § 250 should increase the BOP testing frequency from once every 14 days to once every seven days for drilling and completion operations. Increase blind shear ram testing frequency from once every 30 days to at least once every seven days for well workover operations.

Rationale: Currently, BOP pressure testing is required after installation, at least once every 14 days, and before drilling out each string of casing or a liner (30 CFR § 250.447 [drilling], and 30 CFR § 250.516 [completions]).

Currently Interior Department regulations only require BOP testing of blind shear rams once every 30 days for well workover operations (30 CFR § 250.616).

Prior to 1998, the Interior Department required BOP testing every seven days. In 1998 Interior reduced the testing frequency to 14 days,[175] based on an industry request to save money* and time.[176] Interior's decision to reduce BOP testing frequency was, in part, based on a 1996 study completed by its contractor Tetrahedron Inc., which concluded less testing would result in no appreciable increase in BOP failure rate. Tetrahedron reported that a 32% BOP failure rate occurred regardless of whether the test was run within seven or 14 days[177] but did not draw the more important conclusion—that BOP testing was failing approximately 32% of the time—and that earlier testing could identify these failed BOP systems an entire week earlier if seven-day testing frequency was retained. Additionally, Tetrahedron's study concluded that the BOP failure rate for surface BOP systems actually increased to 50% if testing was extended to 14-day intervals, and did not appear to include any analysis of Arctic offshore BOP systems.†

One Arctic operator, Shell, voluntarily increased BOP testing frequency from 14 days to seven, recommending this step as an important additional prevention measure.[178]

BP's Deepwater Horizon well-blowout recommendations included the need to "strengthen BP's minimum requirements for drilling contractor's BOP testing including emergency systems" and "require contractors to verify blind shear ram performance capability."[179]

Redundant BOP blind shear rams for Arctic operations

Proposal: Redundant blind shear rams should be required on all BOPs.

Rationale: The Interior Department's BOP regulations for drilling new wells currently require one annular ram, two pipe rams, and one blind shear ram (30 CFR § 250.442(a)). Interior's BOP regulations for well completions (30 CFR § 250.515) and well workovers (30 CFR § 250.615) require one annular ram, one pipe ram, and one blind shear ram. Therefore, redundant blind shear rams are not currently required for drilling, completions or workovers.

The Interior Department's made an important first step by requiring independent third-party verification of blind shear ram capability in its October 2010 Drilling Safety Regulation Revisions at 30 CFR § 250.416(f). However, it deferred the requirement to install redundant blind shear rams in all offshore BOPs to a later rulemaking process.[180] One Arctic operator, Shell, plans to voluntarily install redundant blind shear rams in the BOPs it uses for Arctic drilling, recommending this step as an important additional prevention measure for offshore Arctic operations.[181]

The Interior Department's has studied the critical safety importance of blind shear rams, because shear rams are the last line of defense in the BOP. If shear rams are not 100% effective in shutting during a well control situation, an uncontrolled well blowout will result. The 1979 Ixtox blowout was an example of a well blowout where a single set of blind shear rams failed to shear the drill pipe and secure the well.[182]

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* In 1998, Interior estimated that reduced BOP testing would save industry $35 million to $46 million per year.

† Tetrahedron's 1996 study examined 155 BOP test reports, but it did not report the location or service of those BOPs; it is unclear if any Arctic offshore BOP tests were examined. However based on the lack of Arctic offshore drilling at this time, it is unlikely that Arctic BOP testing was reliably examined in this study.

Department of Interior's consulting experts have found that: "Advances in drill pipe metallurgy, combined with larger and heavier pipe sizes used in modern drilling programs have resulted in instances where pipe on a rig may not be successfully sheared and the wellbore sealed. … The latest generation of high ductility pipe, known by various names, has been seen in some cases to almost double the shearing pressure compared to lower ductility pipe of the same weight, diameter and grade."[183] Additionally, tool joints located on the drill string are too thick and strong to be severed by the blind shear ram. Therefore, a driller must carefully plan the handoff location for the drill pipe to ensure that the blind shear ram is in contact with the drill pipe and not the drill pipe tool joint. For this reason it is critical to test the BOP blind shear rams to ensure that the ram is capable of shearing the drill pipe that is planned for use, but it is also important to provide a redundant system as a backup in case the first ram malfunctions.

Remotely operated vehicle access point for subsea Arctic BOPs

Proposal: The Interior Department's regulations at 30 CFR § 250 should specify that the hot stab access point for the remotely operated vehicle, or ROV, connection should be unobstructed and located on top of the subsea BOP. Redundant ROV and diver capability, along with launch and recovery systems for each, should be provided on a support vessel.

Rationale: 30 CFR § 250.442(f) requires subsea BOP stacks to be equipped with ROV intervention capability. However, this regulation does not specify requirements for BOPs located in mud-line cellars, which is typical of Arctic offshore subsea BOP operations. Because Arctic subsea BOPs are located in mud-line cellars, the hot stab access point for ROV connection must be located on top of the BOP to ensure rapid access. Typically, mud-line cellars are not large enough in diameter to provide room for a ROV to access a hot stab point on the BOP.

Interior's regulations do not currently require redundant ROV and diver capability on a support vessel.

BP's Deepwater Horizon well blowout recommendations include the need to "develop a clear plan for Remotely Operated Vehicle intervention for each subsea BOP."[184]

Redundant ROV hot stab panel for subsea Arctic BOPs

Proposal: Interior Department regulations at 30 CFR § 250 should specify that a redundant ROV hot stab panel should be on a seafloor sled located a safe distance away from the well, as a means to operate the subsea BOP if the ROV hot stab panel on the BOP is inaccessible. Redundant ROV and diver capability on a support vessel, along with launch and recovery systems for each, should be provided.

Rationale: 30 CFR § 250.442(b) requires an operable dual-pod control system to ensure independent operation of the BOP system, which means two control pods are provided on the BOP for redundancy. Electrical signal control of the pods is primary. Acoustical, ROV intervention, and deadman controls are secondary. However, because of the increased risk of BOP failure in Arctic operations, the potential malfunction or inability to successfully access the BOP within a mud-line cellar, encroaching ice, or other severe weather conditions, a redundant ROV hot stab panel should be installed for subsea Arctic drilling operations.

One Arctic operator, Shell, plans to voluntarily provide a redundant ROV hot stab panel on a seafloor sled located a safe distance away from the well, and recommends this step as an important additional prevention measure for offshore Arctic operations.

Arctic BOP record-keeping and reporting

Proposal: Operators should be required to keep a record of all incidents of Arctic BOP activation. Data collected would include real-time, remote capture of BOP function data.[*, 185]

Operators should be required to routinely report the Arctic BOP activation frequency and provide an engineering analysis recommending prevention improvements for future drilling and well work. Operators should be required to maintain a history of all inspection records on file.

Rationale: 30 CFR § 250.188 (a)(3) requires incident reporting, including loss of well control. Incident reporting must occur when wells flow through a diverter; there is uncontrolled flow through a failure of surface equipment or procedures; or, there is uncontrolled subsurface flow (an underground blowout) or uncontrolled flow at the surface (a surface blowout). 30 CFR § 250.188 (a)(3) does not require reporting of BOP activations that did not result in uncontrolled flow.

This proposal would require operators to report the number and type of incidents that lead up to activation of an Arctic BOP. This type of data collection and reporting is similar to "near miss" reporting methods used by industry to track and evaluate events that could potentially lead up to a catastrophic failure (uncontrolled flow). These records could be used to assess errors and operational procedures and mitigate future risks. BOPs should be the last line of defense in well control. Activation of the BOP system is an indication that well control improvements are needed in the steps leading to BOP activation.

This proposal is designed to collect operational data that can be used by industry engineers, equipment manufacturers, and regulators to understand the frequency and causes of BOP activation and to develop engineered solutions to mitigate the frequency and risk.

This recommendation is consistent with the National Academy of Engineering/National Research Council, or NAE/NRC, and the National Commission on the BP Deepwater Horizon Oil Spill recommendations,[†, 186] stating that more rigorous near-miss analysis and lessons-learned reporting should be instituted. Unplanned incidents and near misses are valuable tools in advancing state-of-the-art technologies and regulations.

This recommendation would require operators to maintain records of all BOP inspections, because Interior found that American Petroleum Institute Recommended Practice 53 (API RP 53): inspection standard currently referenced for BOP testing, does not include this record-keeping requirement. The new requirement would allow Interior Department inspectors to have BOP records available for audit.[‡, 187]

* Bureau of Ocean Energy Management, Regulation, and Enforcement, *Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout*, 209 (recommended that the agency consider promulgating regulations to require real-time, remote capture of BOP function data that would be beneficial in post-accident source control and subsequent investigations).

† Committee for the Analysis of the Causes of the Deepwater Horizon Explosion, Fire, and Oil Spill to Identify Measures to Prevent Similar Accidents in the Future, *Interim Report on the Causes of the Deepwater Horizon Oil Rig Blowout and Ways to Prevent Such Events*, (recommending improved lessons learned and near-miss analysis); National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling Report, Recommendation A3 (Jan. 11, 2011) (recommending more detailed requirements for incident reporting and data concerning offshore incidents and near misses to allow for better tracking of incidents and stronger risk assessments and analysis; and recommending that: "such reporting should be publically available and should apply to all offshore activities, including incidents relating to helicopters and supply vessels, regardless of whether these incidents occur on or at the actual drilling rigs or production facilities").

‡ Bureau of Ocean Energy Management, Regulation and Enforcement, *Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout* (recommended improved BOP record-keeping requirements).

Arctic OCS tank performance standards

Proposal: The requirement for Arctic OCS tank performance standards should be added to the Interior Department's regulations at 30 CFR § 250, including requirements for offshore crude oil and fuel tanks to:

- Be of double-wall, double-bottom construction, or be fully contained within a protective structure that serves as secondary containment.
- Have a leak-detection system installed in the interstitial space between the tank's double bottom and be equipped to provide automated visual and automated alarms.
- Equipped with automated overflow alarm systems.
- Have leak detection systems and overflow alarms tested prior use and at regular intervals thereafter.
- Be connected by piping to one or more tanks capable of holding the tank contents, such that the tank contents could be immediately transferred to another tank if a leak occurs.
- Be designed and operated to prevent corrosion, including use of corrosion-control coatings, cathodic protection, corrosion inhibitors.
- Be inspected prior to use; at least annually thereafter for the external portion of the tank; and at least once every five years thereafter for the internal portion of the tank.
- Be inspected by a certified tank inspection engineer, and approved for continued use prior to returning the tank to service. Tank inspection standards should be specified.

Rationale: Interior Department regulations at 30 CFR § 250 do not currently include Arctic-specific tank design or tank leak detection and prevention system requirements in its regulations. Tanks at existing offshore facilities currently located in the Beaufort Sea have secondary containment systems installed that include double walls, double bottom construction, and are fully contained within a protective structure that serves as secondary containment. This is a current best practice and should be required as a minimum standard.

Leak detection systems are currently available and technically feasible for installation in the interstitial space between the tank's double bottom and should be equipped to provide automated visual and auditory alarms.

Best technology and operating practices for fuel and crude oil tanks includes the use of: automated overflow alarm systems; testing of leak detection systems and overflow alarms tested prior use, and at regular intervals thereafter; corrosion control; and ensuring a method to move the contents of a failed tank for source control.

The current API Recommended Practice No. 653 (API 653) for tank inspections does not specifically recommend a practice for inspection of offshore tanks in the Arctic. More generally API 653 recommends that tanks be inspected on a five-year external and 10-year internal frequency. It is recommended that this frequency be increased to a one-year external and five-year internal frequency for Arctic offshore tanks that are subject to high corrosion rates due to constant saltwater exposure and thermal impacts that can result in accelerated failure rates.

Arctic OCS well cementing practices

Proposal: Existing Interior Department regulations at 30 CFR § 250.415 should be amended to:

- Include specific standards for cementing through permafrost, methane gas hydrates, and other Arctic drilling hazards (e.g., thaw subsidence and freeze back effects).

- Incorporate API Recommended Practice 65 for cement installation (API RP 65) into the CFR for all wells, not just wells drilled in water deeper than 500′ (at 30 CFR § 250.415(e)).[*, 188]
- Require cement to be evaluated using a Cement Evaluation Tool, or CET, cement bond log, or equivalent well-logging tool. Operators should be required to run CETs[†] and submit well-logging data to the Interior Department as evidence of a successful cement job, or complete immediate remedial cementing action when required and verify through a repeat cement evaluation log that the repair was successful.

Rationale: Cement is a critical structural component of a safe and environmentally sound well. Cement secures the casing and provides a barrier for hydrocarbons to prevent a blowout. Oil and gas leaks can occur when poor quality cement is installed, contaminated with drilling mud, installed incorrectly, or damaged by work on the well. An effective cement job is the foundation of well integrity and is a key risk factor considered in construction of Arctic wells. Historically, poor cementing has been cited as a reason for loss of well control, including in the Deepwater Horizon blowout.

Consistent with National Academy of Engineering/National Research Council recommendations, cementing techniques and quality control/quality assurance procedures should be optimized. Cement evaluation tools are cost effective, technically feasible, and available for use. They should be made mandatory in all offshore wells to reduce risk and improve quality assurance and quality control, or QA/QC, programs.

30 CFR § 250.415 requires an operator to submit a casing and cementing program in its Application for a Permit to Drill. 30 CFR § 250.420 and 30 CFR § 250.421 require the operator to meet certain casing and cementing requirements. In addition, 30 CFR § 250.428 requires the operator to run cement evaluation tools under some conditions. However, these casing and cementing program requirements do not currently include a cement QA/QC plan, nor do they require the operator to run cement evaluation tools in all circumstances. 30 CFR § 250.415(e) requires use of API Recommended Practice 65 for cement installation (API RP 65) only for wells drilled in water deeper than 500′ (at 30 CFR § 250.415(e)).

In the Arctic, cold soil compromises cement strength, and specialty cements are required to ensure that strong, durable cement is formed as a barrier. Conventional cements used in temperate locations are not satisfactory for use in Arctic wells because they freeze before they can set up sufficient compressive strength. Specialized cement systems must be used in the Arctic to ensure that the cement does not freeze before gaining the required compressive strength. Thawing of frozen soils must be prevented. Thawing can increase the amount of cement volume needed and can cause the formations to subside, which can create severe bending stresses on the well casing cement. Not all areas of the offshore have permafrost, but some do. Cement used in subfreezing permafrost-laden soils must exhibit low heat of hydration and set with sufficient strength to provide casing support.[189] The cement slurry must be freeze-protected and must develop compressive strength at subfreezing temperatures. Subfreezing temperatures slow cement hydration reactions, causing cement to freeze prior to developing the requisite compressive strength. Cement hydration is an exothermic reaction, and the heat generated during that reaction can thaw the permafrost; therefore, low heat of hydration cements must be used.

Methane gas hydrates are also commonly encountered when drilling Arctic wells. Methane gas hydrates become unstable during temperature and pressure changes that occur during the cementing process. Gas intrusion

* BOEM recommended amending the CFR to require API Recommended Practices for Cementing (API RP 65).

† Due to the incremental cost of running CETs in offshore and complex wells, such as extended-reach wells, some operators skip this test, relying only on cement displacement volumes and limited pressure testing to estimate cement placement success. This practice may be insufficient to verify cement integrity.

(methane hydrates) into cement can weaken the cement, creating spaces that will allow hydrocarbons to pass through the cement that can result in well control incidents.

Cement is installed in the space between the earthen hole that was drilled and the outside of the casing pipe wall. This space is called the annulus. For cement to be an impermeable barrier, the cement must be placed in the annulus, tested to ensure that it was properly installed, and it must not be damaged or degraded over time. In an ideal cement job, cement is placed in the annulus to provide an impermeable barrier to hydrocarbon flow forming a hydraulic seal in the annulus between the casing and the formation. If a hydraulic seal is not made, pathways exist for hydrocarbons to move through failed cement and can result in well control failures and contamination. Cement sheaths must be properly installed, and damage to that sheath, once installed, must be avoided.

Hydrocarbon leakage occurring though cement is well-documented in petroleum engineering literature. While cementing failure rate data for Arctic offshore wells is not well-documented, in 2001 the Interior Department examined cement failure rates in Gulf of Mexico wells finding that one out of every six cement jobs failed to pass and required repair.[*, 190] A 2007 Interior study examining the causes of offshore blowouts found that cementing problems were associated with a majority of the well blowouts; the study found that 18 of 39 blowouts between 1992 and 2006, and 18 of 70 from 1971 to 1991, were caused by cement failure.[191, †, 192]

Engineering the correct amount of cement is an important step in well construction. Engineers make cement calculations to ensure there is sufficient cement to fill the casing shoe and the entire surface casing annulus, such that cement fills the annulus all the way to the surface.[‡, 193] Another important step in well construction is the procedure used to install the casing and cement. Casing is set into the earthen hole and the annulus is filled with cement by pushing cement down the inside of the casing and up into the annulus space behind the casing. If cement placed in the annulus does not form a good bond with the outer casing wall, it creates a space between the casing and the cement called a "micro-annulus" that becomes a conduit for hydrocarbon movement.[§, 194]

It is very important that the casing is centered in the hole, so that an equal, continuous section of cement is placed in the annulus around the pipe to seal off the annulus and create a uniform cement sheath. Good engineering practice requires that casing centralizers are installed on the outside of the pipe to keep the casing centered in the hole while cement is pumped into the annulus. If the casing is not properly centralized, there will be a thinner cement sheath, or possibly no cement where the pipe is near or contacts the earth wall. Thin areas of cement are easily cracked and damaged. Cement that is not well-bonded to the outside of the casing or earthen hole, or that is damaged by subsequent well activities or seismic events, creates a conduit for hydrocarbon movement.[¶, 195]

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* Harris et al. concluded: "*Approximately one out of six casing shoes in the Gulf of Mexico (GOM) require a cement squeeze after primary cementing*"—meaning that even in 2001 cement installation is not 100% successful and has a failure rate.

† David Izon, E.P. Danenberger, Melinda Mayes, and Minerals Management Service concluded that while well blowout fatalities had decreased, "*the percentage of blowouts associated with cementing operations increased significantly from the previous period.*"

‡ Watson et al. concluded: "*An obvious cause of gas migration to surface is low cement top, where cement does not cover a hydrocarbon zone. While mud weight, during the early stages of the wells life may exert adequate hydrostatic pressure to control flow, over time the mud weight will decrease and allow flow to occur.*"

§ Talabani et al. concluded: "*The existence of mud cake at the formation wall is the primary problem that leads to the weak bond between cement and formation. … These regions allow the passage of water or gas resulting in cement job failure.*"

¶ Watson et al. concluded: "*Earth movement caused by formation subsidence, permafrost thaw, flowing sands and tectonic activity can also impact the cement sheath adversely.*"

Another common problem is contamination of the cement with drilling mud.[*, 196] Drilling mud is located in the well when the casing is cemented. Drilling mud is pushed out of the well and displaced by cement. Ideally all the drilling mud would be removed from the area where the cement is to be installed, and spacer fluids are placed between the drilling mud and cement to separate the two fluids to avoid mixing. Mud cake that remains between

the cement and the formation, and within the cement, provides a weak zone that allows for the passage of hydrocarbons.[†, 197, ‡, 198]

It is good engineering practice to rotate and reciprocate the casing as cement is pumped into the annulus to aid in drilling mud displacement and improve cement installation. Another important step in well construction is cement selection. High-quality cement must be used to create an impermeable[§] barrier to hydrocarbon flow. If poor-quality cement is used, it will not create an effective barrier. Cement permeability varies in proportion to the cement slurry solids/water ratio, cement composition, and placement techniques used, among other factors.

These important engineering designs and operational practices for optimizing cement installation are addressed in API Recommended Practice 65 for cement installation (API RP 65) and should be applied as a minimum standard for Arctic offshore well construction and not just be required by Interior Department wells drilled in water deeper than 500'.

The use of the CET or equivalent technology has greatly improved the accuracy of cement evaluation over prior, commonly used cement bond log tools, and provides important information that can be used to evaluate cement integrity and reduce well construction integrity risk.

Contingency plans for cementing Arctic wells must take into consideration the potential for large washout zones through permafrost requiring 500% excess cement, rather than the more typical 100% excess cement planned. Hole enlargement may occur when warm drilling fluid melts the permafrost. Mud chillers are used to cool the drilling fluid to mitigate this problem.

Shallow unconsolidated Arctic drilling zones, including permafrost zones, have low fracture gradients, which can cause significant fluid loss. Low-density cement slurries may be needed, as well as cement plug placement, to arrest fluid losses.

API Recommended Practice 10B-2, Recommended Practice for Testing Well Cements, includes a section on testing of Arctic cement slurries.

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* Watson et al. concluded: "*A common cause of gas migration is poor mud displacement. If mud is not properly displaced prior to cementing then channel can occur that remain mud filled in the cement sheath. Over time the mud in these channels loses its density and shrinks. … In addition poor mud and filter cake removal prior to cementing will reduce the casing to cement bond and cement to formation bond. These micro annuli form a conduit for gas or other reservoir fluids to flow to surface. … Contamination of cement with these muds may keep the cement from developing the required compressive strength or from gelling at all. The lack of these considerations in an existing wellbore may indicated the mechanism for gas migration.*"

† Talabani et al. concluded: "*Gas migration in the annulus behind the casing gas been recognized as a major completion problem in the oil patch. Despite the efforts of many companies and individual researchers, the problem has remained unsolved. Gas migration in cement occurs during and after the cement is set.*"

‡ Pelipenko and Frigaard concluded: "*Uncontrolled flows of reservoir fluids behind casing are relatively common in primary cementing and can lead to any of the following: blowout, leakage at the surface, destruction of subsurface ecology, potential contamination of freshwater, delayed or prevented abandonment, as well as loss of revenue due to reduced reservoir pressures. One significant potential cause is ineffective mud removal during primary cementing. … As the cement sets, the mud channel becomes dehydrated and porous, allowing reservoir fluids to flow behind the casing along the annulus.*"

§ Permeability is a measure of the rate that gas or liquid will flow through a material.

BP's post-Deepwater Horizon well-blowout recommendations include updating and clarifying cementing practices and QA/QC programs.[199] The Bureau of Ocean Energy Management, Regulation, and Enforcement also recommended improved QA/QC programs for cementing after the Macondo well blowout.[200]

Minimum stock levels for Arctic OCS operations

Proposal: Interior Department regulations at 30 CFR § 250.1617 (Application for Permit to Drill) should be amended to include minimum stock levels for Arctic OCS operations. Operators should be required to provide a minimum drilling stock level plan for Arctic operations to demonstrate that sufficient critical well control materials are onsite and available in case of severe weather delays or halts in supply lines. These materials, at a minimum, should include at least a 30-day supply of: drilling mud, including weighting material and lost circulation additives; cement and other well-plugging material; and fuel (in case inclement weather delays fuel transfers) for the well that is being drilled and all the materials and fuel required for a relief well.

Rationale: Well control operations require sufficient onsite materials. In remote Arctic areas, severe weather can delay or halt supply lines and impact overall logistics (e.g., access, timing, material delivery and storage). Therefore, for Arctic operations, onsite stock levels establish the degree of well control readiness.

30 CFR § 250.418 requires the operator to keep minimum quantities of drilling fluids and drilling fluid materials, including weight materials, at the site, but the regulation allows the applicant to specify the appropriate minimum level. 30 CFR § 250.418 does not specify minimum drilling stock levels for cement and other well plugging materials, fuel, and backup power systems.

This proposal recommends a new requirement be set to establish a minimum 30-day stock level for Arctic OCS operations to ensure materials are onsite and available in case severe weather delays or halts supply lines. A 30-day standard is recommended because most wells take 30 days or less to drill in the U.S. Arctic areas currently leased. The 30-day supply should include drilling mud, including weighting material and lost circulation additives; cement and other well-plugging material; and fuel (in case inclement weather delays fuel transfers) for the well that is being drilled and all the materials and fuel required for a relief well.

Remoteness dictates a different operating philosophy for drilling-program supply with respect to consumables.[201] Because conventional road and rail access is not available to most of the Chukchi and Beaufort seas' coastlines, there is a lack of port facilities. The few port facilities that exist are located in shallow nearshore waters only able to accommodate shallow draft vessels and small resupply transfers. There is one dock in the Beaufort Sea (West Dock near Prudhoe Bay) that can accept larger barge shipments, if dredging operations are conducted in advance. Because land fast ice is present for much of the year, the few port facilities that exist are only accessible a few months of the year. Therefore, Arctic drilling rigs must be capable of being self-sufficient and carry much greater volumes of consumables than would be the case in temperate-water drilling where daily or weekly resupply is an option.

Arctic OCS COCP procedures

Proposal: Interior Department regulations at 30 CFR § 550.220 and 30 CFR § 550.251 for COCPs should be amended to establish specific, quantitative, measurable Arctic thresholds for when exploration or production operations should cease due to weather or logistical impediments or during periods of time when oil spill response is not possible.

Curtailment thresholds should be set for each site-specific project based on a thorough statistical assessment of ice, temperature, visibility, wind, wave height, and oil spill response gaps. Thresholds should be based on site-specific, seasonal factors that will limit response or pose safety hazards, requiring operations to cease. The curtailment threshold analysis should examine personnel and equipment operating limits including drilling rigs, production equipment, vessels, support systems, and oil spill response equipment.

A monitoring program (similar to the ice monitoring program currently used for the COCP) should be instituted to monitor temperature, visibility, wind, and wave height on an hourly basis and forecast those conditions over at least a 48-hour window so that the operator can cease operations when curtailment thresholds are exceeded.

Rationale: The Interior Department currently requires operators to submit a COCP that describes the procedures it will use to identify ice, weather, and other conditions that may require exploration or production operations to be curtailed or shutdown (30 CFR § 550.220 and 30 CFR § 550.251). However, the current regulations do not specify any specific, quantitative, measurable Arctic-thresholds for when exploration or production operations should cease due to weather or logistical impediments, or during periods of time when oil spill response is not possible. The current regulations do not require curtailment of operations when oil spill response is rendered infeasible.

Currently the operator is allowed broad discretion to determine when to curtail or shut down operations because the COCP only includes generalized procedures to determine when to curtail or shut down operations, and does not include specific predetermined thresholds for curtailment or shutdown.

COCPs are successfully used to curtail or shutdown Gulf of Mexico offshore operations due to high winds and storms associated with hurricanes or severe storms. After the Exxon Valdez oil spill in Prince William Sound Alaska, tanker transits and tanker loadings were limited to certain wind, wave, and sea conditions to reduce the risk of a spill when response is not possible. In both cases, specific predetermined thresholds for curtailment or shutdown are preapproved. A similar system should be put in place to monitor all Arctic curtailment thresholds.

The current regulations should require curtailment of operations when oil spill response is rendered infeasible because the oil spill response gap is more significant in the Arctic than in temperate locations. Oil spilled in fall ice conditions that, if unrecovered, could persist in the environment for six months or more until recovery operations could be attempted again the following summer. The magnitude of the potential gap is important to quantify and understand to effectively establish seasonal limitations or other prevention measures.

Weather conditions have a dramatic effect on the tools and tactics available for oil spill response and cleanup, determining what types of recovery methods and equipment can be used and their effectiveness. Cold temperature, storms, and ice can contribute to a range of problems, such as equipment failure and human injury that can greatly prolong or make the cleanup process ineffective. High winds and ice fog found in the Arctic can make it unsafe for response vessels to operate and prevent aircraft from flying, impeding cleanup and delivery of supplies. Vessel and aircraft responses may also be limited by darkness. As temperatures drop, the potential for hypothermia among responders rises, and they must limit the length of their shifts, decreasing the efficiency of response operations.

For example, ice conditions ranging from 30 to 70 percent coverage and waves in excess of 6′ present a major challenge to both mechanical and in-situ burning, or ISB, response. Conventional booms are likely to be ineffective at collecting oil thick enough to be skimmed or burned, and ice conditions are insufficient to contain the oil for efficient skimming or burning. Winds in excess of 20 mph are common in the Arctic, reducing mechanical efficiency and halting ISB operations. The low visibility common in ice fog or whiteout conditions can halt all recovery operations, making air, water, or land transportation unsafe. Freezing temperatures below minus 20 F can reduce human efficiency. A combination of these factors can also preclude operations. It is in these conditions that prevention measures should be instituted.

Arctic OCS seasonal drilling limits when oil spill response is not possible

Proposal: The requirement for Arctic OCS seasonal drilling limitations when oil spill response is not possible should be added to Interior's regulations at 30 CFR § 250. Arctic offshore drilling operations into hydrocarbon bearing zones should be limited to periods when the drilling rig and its associated oil spill response system are capable of working and cleaning up a spill in Arctic conditions, including the time required to control a well blowout. The time required to control a well blowout includes the time required for well capping, containment and relief well operations.

Seasonal limits ensure that drilling through hydrocarbon zones, where there is a potential risk of a well blowout spilling oil into the ocean, does not occur when oil recovery operations are impossible or substantially less efficient at removing oil.

Rationale: Oil spill response techniques are most successful in periods of "open water" during summer months and for spills located on top of solid ice that forms during winter months. Both oil skimming and burning techniques are substantially less efficient during periods of spring broken ice, periods of fall ice freeze-up, and when oil is trapped under ice. Oil spill response techniques are also inefficient in Arctic conditions when winds exceed 20 mph, wave heights exceed 6', and visibility is low.[202]

There are no specific Interior Department regulations limiting Arctic offshore drilling operations into hydrocarbon-bearing zones to periods when the drilling rig and its associated oil spill response system are capable of working and cleaning up a spill in Arctic conditions, including the time required to control a well blowout. Absent a regulatory standard, seasonal drilling limits have not been consistently applied to Arctic drilling programs. For example, Interior effectively applied seasonal drilling limits to Shell's 2012 Chukchi Sea OCS Drilling Project; however, Interior did not apply seasonal drilling limits to Shell's 2012 Beaufort Sea OCS Drilling Project, even though ice sets in earlier in the Beaufort Sea and is of the more dangerous multiyear ice type.[203] Therefore, there is a need to establish standards that would be applied consistently across all projects, during exploration and production drilling.

Most of the Beaufort Sea OCS leases and all of the Chukchi Sea OCS leases are located in water that is too deep for winter exploration from an ice or gravel island, requiring use of floating drilling units operating in summer months.

There are few leases in the nearshore section of the Beaufort Sea that can be drilled from gravel or ice islands. Therefore, most OCS exploration and delineation well drilling in the Chukchi and Beaufort seas will typically be conducted using an MODU that is transported to the Arctic in July, awaiting ice retreat. The drilling rig must leave the Arctic before ice hazards exceed the rig's Polar Class rating.

July, August and September are summer months for the Arctic Ocean and are commonly referred to as the open-water season; however, even during this time, storms, ice, and other hazards can be present. In late September and early October, ice begins to form in the Chukchi and Beaufort seas, entering a period called freeze-up. During freeze-up, open water transitions to a slushy ice mixture and then into a solid ocean ice cover. The freeze-up process can occur in a matter of weeks, creating hazardous ice conditions for floating drilling vessels and their support fleets.

Drilling restrictions in the U.S. Arctic OCS that limit offshore operations to summer could ensure that there is sufficient time left in the operating season to cap a blown-out well, drill a relief well, and clean up spilled oil in open water, thereby providing a critical margin of safety in the proposed plan. Seasonal drilling restrictions, with these specific components, are not included in existing regulations. For example, Greenland requires offshore operators to finish drilling at least 60 days before hazardous late fall/winter ice sets in.[204]

Routine drilling operations that extend to the very last day that it is safe to drill do not allow time to respond to a well control event before winter conditions set in and equipment must leave the Chukchi and Beaufort seas because it becomes unsafe to operate in ice, freezing conditions, and darkness. A spill in the Arctic not contained by freeze-up could continue unabated through the winter.

Arctic OCS exploration and production expertise, experience, capacity, competencies, and qualifications

Proposal: The requirement for Arctic OCS expertise, experience, capacity, competencies, and qualifications should be added to the Interior Department's regulations at 30 CFR § 250. Each operator should be required to demonstrate its Arctic exploration and production expertise, experience, and capacity as part of its Exploration Plan, or EP, or Development and Production Plan application.

The Interior Department should establish Arctic-specific standards for drilling, completion, workover, and facility operation personnel training and qualifications (including cementing contractors, well stimulation contractors, etc.). Interior's regulations should summarize Arctic-specific requirements in a list. For each job type, the following mandatory standards should be listed: training (type and frequency), qualifications, certifications, and years of experience. The operator should be required to maintain a database of its personnel training, and either track its contractors' training or require the contractors to do so, such that these records are readily available to Interior for an audit.

Rational: Existing regulations (30 CFR § 250) do not require a demonstration of Arctic-specific expertise, experience, and capacity prior to obtaining an Arctic OCS lease. Yet, unique operating conditions, Arctic drilling, well control, and facility operations require additional expertise.[*, 205]

Drilling in the Arctic OCS requires specific professional competencies and qualifications that may involve extensive college training, apprentice training and/or long-term work experience. In addition to traditional exploration and production education, training, and experience, personnel working in the Arctic require unique training in Arctic competencies and qualifications. For example, an experienced petroleum engineer may have never worked in the Arctic in his or her career. Interior Department regulations do not require this demonstration.

In 2011, Interior commissioned study concluded:

"The development of qualified and capable workforce for the specific technical challenges of the Arctic exploration requires training of personnel in harsh environment know-how, and creating workplace conditions adapted to a uniquely inhospitable environment. [Personnel] who are conscious of safety, environmental

* BOEM recommended that the agency consider working with industry organizations to revisit the core well control training curriculum used by most companies and training providers, recognizing a need for improved training and qualifications at least for well control.

and social responsibility considerations will respond better to emergency situations. Training should address: evacuation of personnel; emergency rescue equipment; offshore protective equipment; helicopter and marine support; spill response equipment and techniques; waste management; monitoring and control of emission and discharge; and traditional lifestyle of indigenous population."[206]

Interior should examine an operator's previous experience in Arctic hydrocarbon exploration and exploitation; and health, safety, and environment systems. Interior should also review the operator's emergency response plans and previous experience in managing environmental emergency situations in Arctic conditions.

For example, Greenland requires operators to undergo an operator prequalification program to prove they have the expertise, experience, and capacity to "undertake drilling activities offshore in harsh remote Arctic locations."[207]

Interior Department regulations include Well Control and Production Safety Training (30 CFR § 250, Subpart O) and Safety and Environmental Management Systems Training (30 CFR § 250, Subpart S), but do not include specific training and qualification requirements for drilling and workover personnel, such as cementing and well-stimulation contractors.

This proposal is consistent with NAE/NRC recommendations.[208] Norway[209] and Greenland[210] both require the operator to provide extensive information on personnel competencies and qualifications.

BP's post-Deepwater Horizon well blowout recommendations include the need to "enhance drilling and completions competency programs for key operational and leadership positions,"[211] supporting the need to have the right training and experience for the job to prevent accidents. In particular BP noted improvements needed in:

- "BP's in-house expertise in the areas of subsea BOPs and BOP control systems."
- "Critical zonal isolation engineering plans and procedures."
- "Assurance of contractors for all services related to zonal isolation engineering and technical services, including engineering competency, service quality and adherence to relevant standards."

Pollution prevention, air pollution control in the Arctic Ocean

Proposal: The Interior Department's air pollution regulations should be revised at 30 CFR § 550 to:

- Eliminate the exemption formulas set forth in 30 CFR § 550.303(d) and the temporary facility exemptions in 30 CFR § 550.302.
- Require each OCS Exploration Plan and Development and Production Plan to account for the collective emissions of drilling equipment, production facilities, as well as its associated fleet; conduct air quality modeling to assess impacts with all ambient air quality standards and comply with those standards throughout the OCS not just at the shoreline; and to install modern technological controls to limit pollution from significant sources.
- Ensure the Interior Department's air pollution inventory, modeling assessment, and control technology requirements are at least as stringent as the Environmental Protection Agency's.

Rationale: In December 2011, Congress transferred authority for regulation of Arctic offshore exploration, development and production activities that generate air pollution from the EPA* to the Bureau of Ocean Energy Management, or BOEM.[†, 212]

Interior's air pollution control regulations,[213] however, differ fundamentally from EPA's regulations. Interior Department air pollution control regulations were developed in 1980, more than 30 years ago,[‡] and do not include most of the important improvements made in air pollution impact assessment and air pollution control that EPA has adopted in its more modern regulations. Interior's air quality regulations are outdated and do not reflect the best science or technology available today. For example, Interior's regulations exempt many offshore sources from air quality standards and installing air pollution controls, and do not require public review or comment.

EPA, meanwhile, requires baseline data collection, a comprehensive accounting of all air pollution sources, an incremental air pollution impact assessment, air pollution control technology be installed, and provides for public review and comment.

Additionally, EPA has specific air quality standards and requires specific types of oil and gas exploration, development and production equipment to install Best Air Control Technology, Maximum Air Control Technology, or meet New Source Performance Standards or National Emissions Standards for Hazardous Air Pollutants.

The Interior Department's existing regulations establish a three-step review process, with most offshore sources receiving an exemption from air quality impact analysis and control requirements at the very first step. At the first step, projected annual emissions from the regulated "facility"[214] (generally defined as the drilling platform or drillship to the exclusion of support vessels), are compared to an "emission exemption level." The exemption level is determined using a linear equation developed in 1979-1980 that assesses the potential air quality impact based on distance from shore. For most pollutants, the exemption level is 100 tons per year for a source 3 miles from shore, 200 tons per year for a source 6 miles away, 300 tons for a source 9 miles away, 400 tons for a source 12 miles away, etc. If a facility's projected annual emissions are below the exemption level, it is exempt from further regulatory review and any requirement to install controls.[215]

Under Interior's regulations, a large source of air pollution—for example, one that emits 300 tons per year of each of four pollutants: sulfur dioxide, or SO_2; nitrogen dioxide, or NO_2; particulate matter, or PM; and carbon monoxide, or CO; located in close proximity to the shoreline (for example, just under 10 miles from shore)—would be completely exempt from any analysis of its air quality impacts as well as any obligation to install pollution controls. The same source, if regulated by EPA, would be categorized as a "major" source, required to conduct a full air quality impact analysis demonstrating compliance with all applicable air quality standards, and would be required—at a minimum—to apply the "best available control technology" for each pollutant and may also be required to install additional controls depending on the pollution source type.

In the few instances where a facility's emissions exceed the exemption level, Interior's regulations require the owner to conduct preliminary air dispersion modeling to assess whether the facility's emissions will have any

* In 1990, Congress adopted section 328 of the Clean Air Act, specifying that Outer Continental Shelf sources in all coastal waters except for the western Gulf of Mexico would be subject to EPA authority and required to comply with state and federal air quality standards as well as the act's Prevention of Significant Deterioration requirements; offshore sources in the western Gulf of Mexico remained under the jurisdiction of the Interior Department.

† On Dec. 23, 2011, in a rider to the Consolidated Appropriations Act of 2012, Congress amended section 328(a)(1) of the Clean Air Act to transfer authority for regulation of future Outer Continental Shelf activities in the Arctic (i.e., adjacent to Alaska's North Slope Borough) from EPA back to Interior. (BOEM is the entity within Interior that administers the department's air regulations.)

‡ Pursuant to OCSLA, Interior proposed air regulations for offshore operations in 1979 that were adopted March 7, 1980.

“significant” onshore impacts. Under Interior’s regulations, only facilities whose modeled emissions exceed the significance levels, as measured at the shoreline, are required to install pollution controls.[216]

The purpose of the Interior Department’s modeling, in the few cases it is required, is to determine whether the facility’s projected emissions will result in ambient concentrations at the shoreline that exceed certain “significance levels.”[217] The significance levels, which track those used by EPA in 1980 as a screening tool for issuance of Prevention of Significant Deterioration permits, are approximately two percent of the national ambient air quality standards.[218] The national ambient air quality standards have been updated and made stricter since 1980, and EPA has since amended the significance levels upon which Interior’s regulations are based. The Interior Department, however, has not made corresponding changes to its regulations.

There are numerous examples where Interior’s air quality regulations are outdated or inadequate for the Arctic OCS. A few examples follow:

- Interior’s regulations generally limit air pollution from drilling platforms/ships only, sources that account for a small percentage of an Arctic operation’s overall air emissions. In the Arctic, icy conditions and the lack of infrastructure require a fleet of support vessels, including icebreakers, that may account for more than 90 percent of the total emissions associated with drilling.[219] Therefore the Interior Department’s regulations do not account for, nor regulate, the overwhelming majority of the air pollution from offshore operations in the Arctic. By contrast, EPA is required by the Clean Air Act to account for and control emissions from all support vessels within 25 miles of the drilling platform or drillship.[220]
- Interior’s exemption formulas are premised upon a source’s annual emissions, which are not a reliable indicator of the impact from offshore sources in the Arctic, where operations are often limited to an intense four- or five-month drilling season. Under Interior’s formulas, a source in the Gulf of Mexico located 9 miles from shore that emits 299 tons of nitrogen oxides, or NO_x, over a 12-month period is exempt from an air impact analysis and pollution controls. An Arctic source located 9 miles from shore would also be exempt from regulation when it emits 299 tons of pollution during a four-month period—even though the Arctic source is, on a monthly basis, emitting three times as much pollution. Further, the exemption formulas incorrectly assume that operational and meteorological conditions in the Arctic match those in warmer climates. Yet, operations in the Arctic rely on diesel-fueled icebreakers and other support vessels that are not used elsewhere, and meteorological conditions are highly variable even within the Arctic itself, making application of a default exemption formula inappropriate.
- The Interior Department’s regulations establish a significance level for total suspended particulates, or TSP.[221] EPA, meanwhile, no longer regulates particulate pollution using TSP criteria. Standards addressing TSP have been superseded by more detailed and health-protective ambient air quality standards that separately address coarse particulate matter, or PM_{10}, and fine particulate matter, or $PM_{2.5}$, which are better indicators of human health hazards. EPA has adopted “significance levels” for PM_{10} and $PM_{2.5}$.[222]
- Interior’s regulations do not establish significance levels for one-hour concentrations of NO_2 and SO_2. Neither pollutant was subject to a one-hour standard in 1980, but such one-hour standards were recently adopted by EPA owing to research on the adverse health consequences of short-term exposure to these pollutants.[*, 223]

* EPA, in guidance memoranda, has established “interim significant impact levels” for both of these pollutants pending a rulemaking process to establish final levels. *See* Memo. from Stephen D. Page to Regional Air Division Directors re Implementation of the 1-hour NO2 NAAQS (June 29, 2010); Memo. from Stephen D. Page to Regional Air Division Directors re Implementation of the 1-hour SO2 NAAQS (Aug. 23, 2010).

EPA, in guidance memoranda, has established "interim significant impact levels" for both of these pollutants pending a rulemaking process to establish final levels.[224]

Pollution prevention, zero discharge of muds, cuttings, sanitary waste, and produced water in the Arctic Ocean

Proposal: The Interior Department's pollution prevention regulations at 30 CFR § 250.300 should be revised to prohibit discharge of drilling muds, cuttings, sanitary wastes, produced water, and all other discharges, where technically feasible methods of collection exist in the Arctic Ocean (Beaufort and Chukchi seas). Where technically feasible methods of collection do not exist, the operator should be required to demonstrate that it has selected the lowest-impact chemicals by providing supporting toxicological data. Drilling waste should be routed to tanks or vessels, and then transported or piped to an approved subsurface disposal well or waste-handling facility. No drilling muds or cuttings should be allowed to be disposed of offshore.

Rationale: 30 CFR § 250.300 requires pollution prevention and allows the Interior Department to restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. However, it does not strictly prohibit the discharge of drilling muds, cuttings, produced water and sanitary waste into the Arctic Ocean. In the past, Interior has allowed the operator to discharge 8,000-12,000 barrels per well of muds and cuttings waste and 2,000-4,000 barrels per well of sanitary waste.

Water-based drilling fluids and associated cuttings are contaminated with metals and other chemicals that bioaccumulate and persist in the environment. Sanitary waste may introduce contaminates into the ocean where subsistence hunting takes place, if the discharge location is nearby.

Arctic exploration drilling and production facility operators have proved it is technically feasible to collect and transport muds and cuttings to an onshore treatment and disposal facility, either via truck transportation across an ice road or by vessel. Both onshore and offshore treatment and disposal facilities exist in the Arctic and use could be arranged by contracting with the owner of the disposal facility. Alternatively, an operator can build its own facility, or waste can be backhauled to the West Coast when drillships and other equipment leave the Arctic, as they do at the conclusion of each drilling season.

The Arctic Council's April 2009 Arctic Offshore Oil and Gas Guidelines support enhanced pollution prevention requirements for the Arctic, including discharge prevention when technically feasible waste-management alternatives exist, implementation of waste-reduction, reuse, and recycling strategies, and selection of environmentally friendly "green" chemicals.[*]

The Beaufort and Chukchi seas provide habitat to an abundance of marine life, including birds that migrate from around the world and more than 98 species of fish.[225] The seas support one of the most diverse populations of marine mammals in the world, including seals, whales, walruses, and polar bears.[226] The Beaufort and Chukchi seas are highly sensitive to impacts, particularly given the effects of climate change. Warming temperatures and diminishing sea ice threaten not only the marine life of the Arctic, but also the subsistence practices and local cultures of Alaska Natives and local communities. In the next several years, the U.S. Arctic Ocean will almost

* The Arctic Council was established in 1996. Members include the United States, Canada, Denmark, Finland, Iceland, Norway, the Russian Federation, Sweden, the Aleut International Association, Arctic Athabaskan Council, Gwich'in Council International, Inuit Circumpolar Council, Russian Association of Indigenous Peoples of the North and the Saami Council.

certainly face an expansion of industrial activity. In particular, the proposed expansion of drilling in the Beaufort and Chukchi seas threatens to introduce large amounts of pollution into an already stressed ecosystem.

Public access to Arctic exploration and production facility inspections and audits

Proposal: The Interior Department's regulations at 30 CFR § 250 and 30 CFR § 550 should require the operator to make public a copy of all third-party inspections, agency inspection, audit findings and any corrective action required within 30 days of completion. This information should be posted on the operator's or Interior's website.

Rationale: The public is interested in the outcome of third-party inspections and agency inspections and audits. Making these data available to the public in a timely manner will provide the public with confidence that the operator is completing the required third-party audits and that the agency is completing inspections and audits to oversee the operations.

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Appendix II

Proposed Arctic Response Improvements for the Outer Continental Shelf

Recommended Improvements to the Department of Interior's
Title 30, Mineral Resources
Chapter II, Bureau of Safety and Environmental Enforcement, Department of the Interior
Subchapter B, Offshore
Part 254, Oil Spill Response Requirements for Facilities Located Seaward of the Coastline

Contents

List of abbreviations

ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
AOFP	Absolute Open Flow Potential
bopd	Barrels of Oil Per Day
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
DOI	Department of Interior
EDRC	Effective Daily Recovery Capacity
EPA	Environmental Protection Agency
ESA	Environmentally Sensitive Area
GRS	Geographic Response Strategy
IMO	International Maritime Organization
IACS	International Association of Classification Societies
ISB	In-Situ Burning
NOAA	National Oceanic and Atmospheric Administration
NSB	North Slope Borough
NTL	Notice to Lessee
OCS	Outer Continental Shelf
OSRO	Oil Spill Removal Organization
OSRP	Oil Spill Response Plan
PPE	Personnel Protective Equipment
USCG	U.S. Coast Guard
USGS	U.S. Geological Survey
VLD	Very Large Discharge
WCD	Worst-Case Discharge

Background

In 2009, The Pew Charitable Trusts commissioned a comprehensive assessment of the risks, challenges and consequences associated with oil and gas production in the U.S. Arctic Ocean.[1] The assessment was completed by Nuka Research and Planning Group LLC and Pearson Consulting LLC, two firms that provide Arctic oil spill prevention and response consulting services. The Nuka-Pearson report, "Oil Spill Prevention and Response in the U.S. Arctic Ocean: Unexamined Risks, Unacceptable Consequences," was published in 2010 after extensive peer review. Recommendations found in this Appendix are based in part on the Nuka-Pearson report.

In 2011, The Pew Charitable Trusts submitted extensive recommendations to improve Arctic oil spill prevention and response standards to the Department of the Interior.[2, 3] Those recommendations are included in this Appendix, as well as additional recommendations developed in 2012 and 2013 based on further review of international best practices, lessons learned from Shell's 2012 exploration season and lessons learned from the Deepwater Horizon oil spill.

Arctic OCS well capping and containment system performance standards

Proposal: A requirement for Arctic well capping and containment systems should be added to the Interior Department's Oil Spill Response Regulations in Title 30 of the Code of Federal Regulations, Section 254 (30 CFR § 254), as a source control and containment method. The Oil Spill Response Plan, or OSRP, should include a complete description of how the Arctic well capping and containment system would provide source control and containment during a well blowout.

Holders of an Arctic OSRP should own, have on contract, or have available under a mutual aide agreement Arctic well capping and containment systems that are:

- Composed of a high-pressure capping stack[*] and a low-pressure containment dome.[†]
- Located in the Arctic and capable of being on-site and ready to commence operations within 24 hours.
- Capable of capping and containing the well and killing the out-of-control well in the same drilling season.
- Built to Arctic engineering specifications and are at a minimum capable of preventing hydrate formation; handling flow rates at least up to 200% of the worst-case discharge, or WCD; handling pressure at least up to 125% of the maximum anticipated pressure; maintaining station over or near the blowout; and keeping system components enclosed and protected (e.g., winterized).

* A high-pressure capping stack is a high-pressure blowout preventer with two blind shear rams fitted with connecting hoses and assemblies to flow back recovered well fluids to a surface processing vessel.

† A low pressure containment dome is placed over the well if the high–pressure capping stack fails to seal. The dome is fitted with connecting hoses and assembly to flow back recovered well fluids to a surface processing vessel.

- Designed to include Polar[*,†] Class vessels appropriate for the ice conditions that will be encountered during the entire period of operation, address reduced buoyancy near the blowout site, be equipped to deflect and/or withstand encroaching ice; and have system components enclosed and protected (e.g., winterized).
- Capable of remaining on site and designed to withstand anticipated ice and weather conditions that might be encountered for at least 60 days after the blowout occurs (or longer if site-specific planning indicates a need for a longer period of time), in order to ensure the system is capable of operating in ice and adverse conditions that may be encountered while well capping operations are underway.
- Outfitted with necessary supplies and equipment to operate in Arctic conditions.
- Staffed with trained and qualified personnel with Arctic experience who are capable of completing a well capping and containment operation in Arctic conditions.
- Physically tested in the Arctic conditions expected for that drilling location prior to the drilling season and each year annually thereafter, and proven successful and reliable for the intended purpose.
- Subject to independent third-party expert review and inspection by an Arctic engineering expert, prior to the drilling season, and the expert's findings be made available to the Interior Department and the public.
- Inspected by the Interior Department and confirmed to be operational and appropriate for its intended service prior to OSRP approval by Interior. Interior's engineers and inspectors should be present during all Arctic testing.

Drilling should not commence until the Interior Department verifies that Arctic well capping and containment systems are capable of meeting these conditions.

If Arctic well capping and containment systems are shared by more than one operator and a blowout occurs, all drilling operations that rely on this system must cease, because this equipment will be tied up controlling the blowout and will not be available if another blowout occurs.

Arctic well capping and containment systems should be subject to an annual Interior Department inspection and audit, whenever these systems are included and relied upon in an approved plan.

As a practice, Interior requires that operators run a Well Containment Screening Tool to examine site-specific well construction design and geologic integrity for the potential for a well blowout to bypass a well capping stack; however, this requirement should be made mandatory in regulation.[4]

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* The International Association of Classification Societies, or IACS, Requirements Concerning Polar Class ,2011, uses the term "Polar Class" to describe the type of ships constructed of steel and intended for navigation in ice-infested waters, except icebreakers. The Polar Class notation is used to classify vessels used in ice-infested waters with respect to operational capability and strength. IACS uses seven Polar Class designations, PC1 through PC7. A PC1 classification is the strongest vessel capable of year-round operation in all polar waters, decreasing in steps to a PC7 (the lowest-strength classification) for a vessel capable of summer and autumn operation in thin, first-year ice, which may include old ice inclusions.

† The International Maritime Organization, or IMO, Guidelines for Ships Operating in Polar Waters (2010), also uses the term Polar Water and Polar Class Vessels to address the additional risk imposed on vessels due to the harsh environmental and climatic conditions in polar waters, including additional demands on navigation, communications, lifesaving appliances, main and auxiliary machinery, environmental protection, and damage control. The IMO Guidelines for Polar Class vessels address the fact that when ice is present, it can impose additional loads on the hull, propulsion system, and appendages. The IMO 2010 Guidelines state that "only ships with a Polar Class designation or comparable alternative standard of ice-strengthening appropriate to the anticipated ice conditions should operate in polar ice-covered waters."

OSRP holders should provide a complete description of its well capping and containment system in its OSRP because this equipment provides an important oil spill source control and containment function. The OSRP should explain how these well capping and containment system standards are met.

Rationale: Interior Department regulations at 30 CFR § 254 do not currently include Arctic well capping and containment system standards and do not require an OSRP to provide information on how well capping and containment systems will be used to control and contain an oil spill.

Arctic-specific well capping and containment systems are needed for the Chukchi Sea and Beaufort Sea Outer Continental Shelf, or OCS, drilling programs. The Arctic Ocean's severe weather conditions require built-for-purpose equipment. Temperate water systems will not be suitable for the Arctic. Arctic operators should be required to either own, or have on contract, a system that meets Arctic engineering standards that includes a well capping stack, containment dome, and surface processing vessel to control a blowout. The system should be located near the well site to ensure rapid well control. Bringing a system from the Gulf of Mexico would take weeks, and such a system would not be designed for Arctic conditions.

A well containment system is needed, in addition to the well capping system, to control a well blowout where well capping alone could result in hydrocarbons escaping/broaching to the sea. After the BP Deepwater Horizon oil spill, where a high-pressure capping stack failed to control the well blowout, and a low-pressure containment dome with connecting hoses and assembly to flow back to a surface processing vessel was required to control the well, the Interior Department required all OCS operators to provide a well capping and containment system. In 2011 a well capping and containment system was built for the Gulf of Mexico.[*,5] Shell is in the process of building a well capping and containment system for the Arctic, which has yet to be approved.

On Nov. 8, 2010, Interior issued a temporary Notice to Lessee, or NTL, No. 2010-N10 requiring a well capping and containment system.[6] While Interior's NTL was an important step in improving well control requirements, it was issued as a temporary measure and needs to be replaced by a more permanent regulatory revision to ensure this requirement remains in place after 2015. NTL 2010-N10 expires on Nov. 8, 2015. Additionally, NTL 2010-N10 provides general instructions on review and approval of well capping and containment systems, but it does not provide specific Arctic well capping and containment engineering standards or testing requirements.

Arctic OCS relief well rig performance standards

Proposal: The requirement for an Arctic relief well rig performance standard should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254 as a source control and containment method, and the OSRP should include a complete description of how the Arctic relief well rig would provide source control and containment during a well blowout.

An Arctic relief well rig performance standard should include the following:

- OSRP holders should be required to own, have on contract, or have available under a mutual aide agreement a Polar Class[7] or equivalent[8] drilling rig capable of drilling a relief well at the proposed location and for the period required to complete the relief well.

* Marty Massey reports that a well capping and containment system was built for the Gulf of Mexico that is capable of operating in depths up to 10,000′, including a surface processing facility capable of 60,000 barrels of liquid per day and 120 million standard cubic feet of gas per day, supported by tanker vessels capable of holding 700,000 barrels.

- The drilling unit must be identified by name and capability in the OSRP, including mobilization plans to and from the site.
- The relief well rig should be located in the Arctic, capable of suspending operations and providing relief well assistance to the drilling rig where the well blowout has occurred. The relief well rig must be on-site within 24 hours if it is not drilling another well, or within 48 hours if the relief well rig is drilling another well (and must suspend that well prior to commencing relief well services).
- The relief well rig must be a second rig. The operator cannot assume that the primary drilling rig, where the well blowout occurred, is capable of moving away from the well blowout and drilling its own relief well, because most drilling rigs are damaged during serious well blowout events and would not be capable of providing its own relief well drilling assistance.
- The period required for an Arctic relief well is assumed to take at least 60 days. Drilling operations must cease at least 60 days prior to ice and weather conditions that exceed the relief well drilling rig and support vessels capabilities, based on at least 10 years of historical weather and ice data.
- The relief well rig should be equivalent to or more robust than the rig used to drill the original well requiring relief well assistance. The drilling unit with the least capability sets the limit for drilling activities, such that the 60 day period is counted from the time at which ice and weather conditions prevent safe drilling operations by the least capable rig.
- The period of time to drill a relief well may take longer based on a site-specific analysis that is estimated from the first day the well is spudded until the well is plugged, abandoned, and secured with at least two well control barriers, or the well is placed on production. Therefore, a relief well timing estimate must be at least 60 days or longer based on a site-specific calculation.
- If the relief well will take longer than 60 days, drilling operations must cease with sufficient time to complete the relief well prior to ice and weather conditions setting in that exceed the relief well drilling rig and support vessels capabilities. This analysis must be based on at least 10 years of historical weather and ice data.
- The relief well rig should be capable of safely operating in Arctic conditions and suitable to drill in Arctic conditions for the entire period a relief well is required.
- Relief well rigs should be allowed to conduct simultaneous drilling operations; however, drilling operations should be sequenced to ensure that at least one rig (the relief rig) is not drilling through a hydrocarbon zone while other rigs (that rely on that relief rig) are penetrating a hydrocarbon zone. This way the relief well rig would be immediately available to suspend drilling operations and provide the intended relief well assistance.
- Consistent with international standards, all floating offshore drilling rigs operating in Arctic ice conditions, including primary and relief well rigs, should meet Polar Class[9] or equivalent[10] standards.
- The relief well rig must be outfitted with necessary supplies and equipment to operate in Arctic conditions and be staffed with trained and qualified personnel with Arctic experience who are capable of drilling a relief well.
- The relief well rig should be subject to independent, third-party expert review and inspection by an Arctic engineering expert, and the expert's findings be made available to the Interior Department. The system should be inspected by the Interior Department and confirmed to be operational and appropriate for its intended service prior to OSRP approval by Interior.
- Drilling should not commence until the Interior Department verifies that the Arctic relief well rig is capable of meeting these conditions.
- Thereafter, the Arctic relief well rig should be subject to independent, third-party expert review and Interior

- Department inspection and audit at least once per year, whenever the rig is included and relied upon in an approved plan.

Arctic OSRP holders should provide a complete description of its relief well rig capability in its OSRP and provide sufficient information to explain how these standards are met.

Rationale: Interior Department regulations do not currently include Arctic relief well rig performance standards and do not require OSRPs to include a complete description of its relief well rig capability to control and contain a well blowout. Yet, relief wells are a standard emergency response and are required as a minimum standard in other Arctic countries (e.g., Canada and Greenland).

Interior's Notice to Lessees NTL No. 2010-N06[11] requires that relief well rig planning include information on the time required to locate a rig, mobilize it to the drilling site, and drill the relief well. But the NTL does not require the relief well to be located on-site, and immediately available, nor does it include the specific Arctic standards for relief well rigs specified above.

Relief wells are the ultimate well blowout source control measure. Well capping and containment systems are not always capable of stopping or slowing the blowout prior to drilling a relief well. Therefore, it is critical to have a solid relief well drilling plan in place and a rig located in the Arctic to immediately execute that plan.

In the Arctic, there is a very limited window of time to drill a relief well, increasing the importance of having an Arctic-capable second rig already located in the Arctic to provide immediate assistance. Delayed start of a relief well and inability to complete the relief well before the rig must leave the location due to ice could result in a blowout continuing for six months or more. The size of a worst-case well blowout, and the amount of oil spilled into the environment, will be a function of the time required to transport a relief well rig to the drilling site and the time required to drill the relief well.

To expedite relief well operations and reduce the spill size, the relief well rig must be located close by and be immediately available. Planning for a relief well prior to drilling rather than waiting until an emergency situation has arisen will expedite relief well design, permitting, and planning. While additional permitting and review may be required prior to drilling the actual relief well, preplanning will expedite the process, especially for offshore wells.

While the Interior Department has approved plans in which an operator proposes to drill a relief well with the rig that was involved in the well blowout, this should not be approved for future drilling operations because it's a risky plan. Operators should not be allowed to rely on the primary rig for drilling a relief well, because most drilling rigs and their associated blowout prevention systems are damaged during the well blowout and would not be a reliable alternative for relief well service.

Both Canada and Greenland have a two-rig drilling policy. Both countries require that a relief well rig be located in the same area of drilling at the same time.

Canada requires offshore drilling operations to have a designated relief well drilling rig that is capable of drilling a relief well to kill an out-of-control well during the same drilling season (commonly referred to as the "same-season-relief-capability").[12] More specifically, Canada requires the operator's application to describe the relief well plans, procedures, technology, and competencies required to kill an out-of-control well during the same drilling season, including:

- Identification of the drilling unit that will be used, including mobilization details.

- Identification of a minimum of two suitable locations for drilling a same season relief well, including shallow seismic interpretation of the top-hole section.
- A hazard assessment for positioning the relief well close to the out-of-control well.
- Identification of preferred kill method on the basis of estimated blowout rates, including necessary pumping capacity.
- Confirmation that the relief well drilling unit, support craft, and supplies are available and can drill the relief well and kill the out-of-control well in the same drilling season.
- Confirmation of the availability of well equipment and specialized equipment, personnel, services, and consumables to kill the out-of-control well during the same drilling season.
- Contingency plans for the relief well.
- An estimate of the time that it would take to drill the relief well and kill the out-of-control well in the same drilling season.
- The sequence in which these measures would be implemented.
- The time it would take to implement each measure.
- A description of constraints or limitations including prevailing environmental conditions (e.g., ice encroachment or adverse weather).
- The availability of competent people, equipment, drilling unit, and consumables.
- A description of how all available intervention techniques, in addition to a relief well, will be used so that the flow from an out-of-control well can be stopped as quickly as possible.
- A description of the related strategies and preparedness to drill a relief well using a second drilling unit, including any advanced planning, preparation, and staging to reduce the time required to kill the out-of-control well.*

Greenland has established very specific requirements for relief well rigs in its recent approval of Cairn Energy's Exploration Program drilling off the west coast of Greenland.[13] The requirements included that:

- Drilling rigs meet the International Maritime Organization, or IMO, Guidelines for Ships Operating in Polar Waters.
- Drilling operations cease 60 days prior to hazardous ice conditions setting in that would preclude relief well drilling, meaning that Greenland assumes the relief well could take up to 60 days to drill.
- Both drilling units are fully functional and comparable with regard to being able to drill a relief well.
- The drilling unit with the least capability sets the limit for drilling activities, such that the 60-day period is counted from the time that ice and weather conditions prevent safe drilling operations by the least capable rig.
- Independent third-party review of the rig and personnel capabilities be completed.
- Equipment and material be onboard the drilling rig to enable immediate commencement of a relief well.
- Documentation be provided to verify the ability to meet the "two-rig policy."
- The operator adheres to the "two-rig policy" throughout the whole drilling season.

* Canada allows operators to propose alternative plans to meet these objectives based on project-specific and site-specific information.

Norwegian drilling standards require advanced planning for a relief well, including:[14]

- Identification of a minimum of two suitable locations for drilling a relief well, including shallow seismic.
- Interpretation of the top-hole section.
- Assessment of methods for positioning the relief well close to the blowing well.
- Identification of preferred kill method on the basis of estimated blowout rates, including necessary pumping capacity.
- An overview of equipment requirements for the installation/vessel performing the relief drilling and well killing.
- Identification of time critical activities.
- An overview of availability of well equipment and specialized equipment and services.
- An overview of drilling rigs which can be used and possibly mobilized.
- The chosen well killing strategy that would be initiated as soon as possible. And, an alternate (backup) strategy to be implemented depending upon the probability of failure of the primary strategy.

Some of these Canadian, Greenlandic, and Norwegian standards have been integrated in the section above ("Arctic OCS relief well rig performance standards"), and others are included in section below.

Arctic OCS emergency well control plans

Proposal: The requirement for an Arctic emergency well control plan should be added to Interior's Oil Spill Response Regulations at 30 CFR § 254 as a source control method, and the Arctic emergency well control plan should be included in the OSRP to demonstrate source control and containment capability.

The Arctic emergency well control plan should cover the primary rig, well capping and containment equipment, secondary relief well rigs, and additional well barriers. It should also be site-specific and appropriate for Arctic drilling operations, adverse weather (e.g., ice and freezing temperatures) subsurface conditions likely to be encountered (e.g., permafrost, shallow methane gas hydrates) darkness, remote logistical challenges, etc.

Well control drills should be conducted prior to approving the permit for drill in order to test an operator's relief well, well capping and containment plans.

The Arctic emergency well control plan should contain a specific section describing relief well rig contingency plans including:

- Identification of the Arctic relief well drilling unit that will be used, including mobilization details.
- Confirmation that the Arctic relief well drilling unit, support craft, and supplies are available and can drill the relief well and kill the out-of-control well in the same drilling season.
- A description of the related strategies and preparedness to drill a relief well using a second drilling unit, including any advanced planning, preparation, and staging to reduce the time required to kill the out-of-control well.
- A description of how all available intervention techniques, in addition to a relief well, will be used so that the flow from an out-of-control well can be stopped as quickly as possible.An estimate of the time that it would take to drill the relief well and kill the out-of-control well in the same drilling season.

- The sequence in which measures would be implemented.
- The time it would take to implement each measure.
- A description of constraints or limitations including prevailing environmental conditions (e.g., ice encroachment or adverse weather).
- Confirmation that trained and qualified personnel, equipment, drilling unit, and consumables will be on-site to carry out the relief well plan, including the name of the Arctic relief well engineering experts that will be on contract and available to implement the plan.
- Two alternate relief well locations for each well. Both relief well locations should be fully identified, permitted, and surveyed for shallow gas prior to operations commencing on the primary well site. Relief well sites should be evaluated to ensure the current profiles, benthic character, seabed topography, and rig access plans are fully suitable for relief well operations.
- Preplanned relief well design trajectories based on various well blowout scenarios.
- A hazard assessment to identify safe positions for the relief well rig close to the out-of-control well.

The Arctic emergency well control plan should contain a specific section describing well capping and containment contingency plans including:

- Identification of the Arctic well capping and containment system that will be used, including mobilization and deployment details.
- Confirmation that the Arctic well capping and containment system, support craft, and supplies are available and can cap and contain the well and kill the out-of-control well in the same drilling season.
- A description of the related strategies and preparedness to cap, contain and kill an out-of-control well including any advanced planning, preparation, and staging to reduce the time required.
- An estimate of the time that it would take to cap, contain, and kill the out-of-control well in the same drilling season.
- The sequence in which measures would be implemented.
- The time it would take to implement each measure.
- A description of constraints or limitations including prevailing environmental conditions (e.g., ice encroachment or adverse weather).
- Confirmation that trained and qualified personnel, equipment, drilling unit, and consumables will be on-site to carry out the well capping and containment plan, including the name of the Arctic well control engineering experts that will be on contract and available to implement the plan.
- A hazard assessment for positioning Arctic well capping and containment system close to the out-of-control well.

Rationale: To ensure heightened levels of preparedness in the Arctic OCS and to reduce the amount of time required to respond to a blowout emergency, the Interior Department should require operators to include an Arctic emergency well control plan in their OSRP. These emergency plans would detail the availability of well control measures (such as relief well drilling and well containment) and the steps and time to implement those measures successfully. In the event a blowout occurs, this process will ensure that Interior is already familiar with the operator's response methods, therefore speeding up the well control and relief well drilling approvals needed during an emergency.

Interior Department regulations do not currently require an Arctic well control plan that meets the specifications listed in this proposal. By comparison, Greenland requires detailed emergency well control plans including identification of two alternate relief well locations to reduce the amount of time required to commence relief well operations.

More specifically, the following standards are included in offshore exploration well approvals in Greenland:[15]

- A well control drill should be conducted ahead of the drilling season to test an operator's relief well plan and well capping strategy.
- Two alternate relief well locations should be fully identified, permitted, and surveyed for shallow gas prior to operations commencing on the primary well site.
- Relief well sites should be evaluated to ensure the current profiles, benthic character, seabed topography, and rig access plans are fully suitable for relief well operations.
- Preplanned relief well design trajectories should be approved based on various well blowout scenarios; final well design trajectories should be approved prior to actual relief well drilling.

Additionally, Canada, Greenland, and Norway require the emergency well control planning procedures described in the section above, "Arctic OCS emergency well control plans."

Evidence of an Arctic emergency well control plan will ensure that the plan has been developed, site-specific hazards have been evaluated, and the plan is appropriate for the Arctic. This proposal is consistent with recommendations of the National Commission on the BP Deepwater Horizon Oil Spill,[16] whereby the Commission recommended that source control plans be submitted for review and approval both as part of the Oil Spill Response Plan and as part of the permit-to-drill application.

This recommendation is also supported by well control experts, such as Alert Disaster Control, which recommends that it is "imperative that we recognize the significant value of establishing well control management systems, in particular, the development of Level 1: Blowout Contingency Plans, Level 2: Emergency Response Plans, and Level 3: Crisis Management Plans. This in turn leads to the testing of these systems, our personnel, and their competencies through ongoing well control training, emergency response drills and exercises."[17] The North Slope Borough, or NSB, the local government for northern Alaska, requires all offshore operators to include a relief well drilling plan and an emergency countermeasure plan in all offshore permit applications from the shoreline to the three-mile limit.[18] The application must include identification of suitable alternative drilling rigs and identify alternative relief well drilling sites; identification of support equipment and supplies including, mud, casings, and gravel supplies that could be used in an emergency; and an estimate of the time required to commence drilling and complete a relief well.

The state of Alaska requires all offshore operators to develop a blowout contingency plan.[19]

Arctic OCS well control expert contracts

Proposal: The requirement for a contract with an Arctic well control expert should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254, and a well control expert should be named in the OSRP, including the following:

- OSRP holders should have a signed contract with an Arctic well control expert capable of providing onsite expert assistance during a well blowout.

- Evidence of a signed contract should be provided in the OSRP application, and the contract term should cover the entire permitted period, or the permit should be limited to the time period when the contract is valid.
- The Arctic well control expert should have personnel trained, qualified, and experienced to work in Arctic conditions and equipment suitable for Arctic operations.
- Specific standards for the amount of experience, the type of qualifications and training, and the type and amount of equipment required to become an Arctic well control expert should be established in regulation.
- Arctic well control experts should be present on the rig when the well is spudded and remain on the rig until the well is plugged and abandoned.

Rationale: Interior Department regulations do not currently require evidence of a contract with a well control expert that has specific experience in Arctic well control. Most operators currently working in the U.S. Arctic indicate they have contracted with a well control expert and that the expert can be flown in, typically from the Gulf of Mexico, Canada, or United Kingdom, to assist in a well blowout. There is no current process in place to verify that the selected expert has Arctic experience drilling wells through permafrost or dealing with remote logistical challenges, ice, and freezing temperatures.

Travel from the Gulf of Mexico or the U.K. can take several days, delaying expert assistance. Optimally, the expert should be located at the drilling site. Alternatively, the expert should be immediately available and located in Alaska, for immediate dispatch to the drilling location.

The North Slope Borough requires all offshore operators to include a relief well drilling plan and an emergency countermeasure plan in all offshore permit applications from the shoreline to the three-mile limit.[20] The application must identify an Arctic well control expert.

Polar Class support vessel requirements for Arctic oil spill response

Proposal: Requirement for Polar Class support vessels should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254 for operations that are conducted in Arctic ice-infested waters, and the OSRP should provide information to show how these standards are met.* Standards should include the following:

- Operators should be required to provide a sufficient number of Polar Class and icebreaking vessels in the U.S. Arctic Ocean region to support safe operation, to provide towing assistance, and to support source control and spill response operations.
- All fuel should be transported in double-hulled vessels and supported with sufficient tug assistance to avert a potential collision or grounding.
- Vessel captains and pilots should have experience navigating in the Arctic (e.g., state-licensed marine pilots).
- A sufficient number of shallow draft vessels capable of operating in ice-infested waters should be provided to allow oil spill responders to recover oil spilled into shallow marine waters and along remote shorelines.
- All vessels should meet the IMO Guidelines for Ships Operating in Polar Waters (2010).

* The term Arctic waters includes the Beaufort and Chukchi seas. The term polar waters includes Arctic and Antarctic waters.

- The number and type of vessels should be determined by Interior, in consultation with the U.S. Coast Guard, or USCG, based on a site-specific/project-specific analysis.
- Vessels should be inspected by a third-party expert from a technical classification society, or a licensed professional engineering inspection or certification firm, to ensure vessels are in good condition and are suitable for operation in the Arctic. The inspector should consider the vessel's fitness for planned operations and in the event of unplanned operations that may require it to remain at the drill site past the approved drilling season.
- The operating season should end with sufficient lead time to ensure that all vessels can be docked for the winter, unless that vessel meets a Polar Class 1 rating for year-round Arctic operation.

Rationale: Interior Department regulations do not currently require Polar Class support vessels for Arctic oil spill response operations. To be successful, Arctic oil spill response operations need to be supported by Polar Class vessels that are capable of safely operating in ice-infested waters, especially if spill response activities could continue into freeze-up conditions and ice management support is necessary to cover well control operations such as containment and/or relief well drilling.

To ensure that oil recovery can continue during these vital operations, OSRPs should include vessels capable of operating in ice-infested waters with the primary responsibility of supporting spill response efforts. Alaska Clean Seas, or ACS, is the primary Oil Spill Removal Organization, or OSRO, operating in the Chukchi and Beaufort seas and does not have any ice class or Polar Class vessels in its inventory.

There are no U.S. Coast Guard stations north of the Arctic Circle, and the United States only has one functional icebreaking vessel (M/V Healy) and one under repair (M/V Polar Star). Alaska's small ports and airports are incapable of supporting an extensive and sustained airlift effort, and in most locations along the Arctic coastline there are no roads or ports to serve spill response efforts.

This recommendation is consistent with the IMO Guidelines for Ships Operating in Polar Waters (2010). Greenland requires vessels conducting exploration operations off the coast of Greenland to meet the IMO standard.[21]

The IMO Guidelines for Ships Operating in Polar Waters (2010) addresses the additional risk imposed on vessels due to the harsh environmental and climatic conditions existing in polar waters, including additional demands on navigation, communications, lifesaving appliances, main and auxiliary machinery, environmental protection, and damage control. The IMO Guidelines for Polar Class vessels address the fact that when ice is present, it can impose additional loads on the hull, propulsion system, and appendages.

Key provisions of the IMO 2010 Guidelines[*, 22] include:

- "Only those ships with a Polar Class designation or comparable alternative standard of ice-strengthening appropriate to the anticipated ice conditions should operate in polar ice-covered waters."
- "The combination of hull structural design, material quality, subdivision and segregation measures prescribed in the Guidelines and Support standards should be adequate to reduce the risk of human casualties, pollution incidents or ship losses to acceptably low levels of probability during prudent operations in polar waters."
- "No pollutants should be carried directly against the shell in hull areas at significant risk of ice impact."

* Key excerpts are listed in this document; however, a complete set of guidelines can be found in the IMO document *Guidelines for Ships Operating in Polar Waters, 2010.*

- "Operational pollution of the environment should be minimized by equipment selection and operational practice."
- "Key safety-related, survival and pollution control equipment should be rated for the temperatures and other conditions which may be encountered in the service intended."
- "Navigation and communications equipment should be suitable to provide adequate performance in high latitudes, areas with limited infrastructure and unique information transfer requirements."
- "Sea suction(s) should be capable of being cleared of accumulation of slush ice."
- "Special attention should be drawn to the need for winterization aspects."
- "All ships should have structural arrangements adequate to resist the global and local ice loads characteristic of their Polar Class."
- "Each area of the hull and all appendages should be strengthened to resist design structure/ice interaction scenarios applicable to each case."
- "Materials used in ice-strengthened and other areas of the hull should be suitable for operation in environment that prevails at their location."
- "Abrasion and corrosion resistant coatings and claddings used in ice strengthened areas should be matched to the anticipated loads and structural response."
- "All Polar Class ships should be able to withstand flooding resulting from hull penetration due to ice impact."
- "All Polar Class ships should have double bottoms over the breadth and the length between forepeak and afterpeak bulkheads."

Arctic OSRO standards

Proposal: Mandatory minimum Arctic OSRO standards should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254 for operations that are conducted in Arctic ice-infested waters and the OSRP should provide information to show how these standards are met.* Standards should require:

- Polar Class vessels, Arctic-grade skimmers, in-situ burning, or ISB, equipment and personnel qualifications, and training.
- Arctic OSRO training and qualifications standards to ensure sufficient ability to remove oil in a range of ice conditions.
- Oil spill response personnel Arctic training and qualifications for oil spill response with Arctic tactics.
- Personnel trained on the safe and effective use of mechanical response tools and ISB;
- Personnel who are familiar with Arctic operations and safety standards;
- Personnel who have experience navigating vessels in ice and ice fog, and operating aircraft in subzero temperatures and through ice fog, and landing on ice.
- Arctic OSROs serving multiple members in separate geographic areas (such as the Chukchi and Beaufort seas) to have equipment and personnel depots in each geographic area they serve, and have them stored at optimal locations for immediate deployment.

* The term Arctic waters includes the Beaufort and Chukchi seas. The term polar waters includes Arctic and Antarctic waters.

- Response equipment to be pre-staged to provide sufficient oil removal resources until additional equipment can be brought in from a nearby in-region Arctic response depot by land, water, or air.
- Arctic OSROs to keep records of their equipment inventory, maintenance records, drills, and training exercises to demonstrate their capability to respond to a WCD, or a portion of a WCD as specified in the OSRP that they intend to serve.
- These standards to be mandatory for OCS exploration and production operations and verified through inspections and field tests of equipment and tactics.

Rationale: The USCG has a voluntary program where OSROs can be classified to respond to spills in various types of water, including rivers/canals, the Great Lakes, inland, nearshore, offshore, and open ocean.[23] These general standards do not account for unique climate conditions such as the Arctic. The offshore classification, for example, is focused on meeting mechanical response requirements in temperate waters. Therefore, an OSRO equipped only to operate in temperate waters could receive approval to operate in the Arctic without any specialized Arctic-grade equipment, training, or expertise and can be listed in a company's Oil Spill Response Plan. Interior relies on the USCG OSRO classifications in its assessment of whether operators in the OCS meet federal spill response requirements. Therefore, OSROs operating in Arctic regions can obtain OSRO certification without Polar Class vessels, Arctic skimmers, ice capable boom, proper ISB equipment, and remote logistical support capabilities, all of which are critical response equipment for the Arctic marine environment.

In 2001, an Interior Department contractor found that "Spill recovery operations in ice require effective ice management. Currently there is only one spill response vessel in the Arctic with this capacity. Spill response training for vessel crews in low temperature environments is identified also as a potential limitation, if the demand for performing spill recovery operations increases."[24]

Arctic OCS ISB equipment and training standards

Proposal: Arctic ISB equipment and training standards should be added to Interior's Oil Spill Response Regulations at 30 CFR § 254 for operations that are conducted in Arctic ice-infested waters, and the OSRP should provide information to show how these standards are met.* The standards should require that:

- Arctic ISB equipment and training standards be established to ensure that there is sufficient in-region capability to respond to at least the first 30 days of an oil spill.
- The amount of ISB equipment for each OSRP be established using enhanced recovery calculation methods and including sufficient equipment to conduct sustained burning operations for at least a 30-day period, with sufficient equipment to burn the entire spilled volume.
- Personnel have training and qualifications in Arctic ISB deployment and operation, and vessel captains and pilots have experience navigating in Arctic waters.
- Arctic-grade ISB equipment be used, including, but not be limited to, ice-booms capable of thickening oil to the required 2-5 mm thickness to sustain a burn; aircraft and helitorch systems designed to operate in subzero temperatures; vessel-based ignition systems designed to operate in subzero temperatures; landing craft capable of accessing remote shores where docks are not present; equipment to recover burn residue; and cold weather personal protective equipment, or PPE.

* The term Arctic waters includes the Beaufort and Chukchi seas. The term polar waters includes Arctic and Antarctic waters.

- The OSRP include evidence that the plan-holder either owns, or has under contract, sufficient in-region ISB equipment and trained and qualified personnel to operate that equipment.
- The OSRP include evidence that the plan-holder owns, has under contract, or has available under a mutual aide agreement a continuous supply of ISB equipment and trained and qualified personnel to supplement the in-region ISB equipment and personnel for the entire response operation, up to respond to the WCD.

Interior should maintain an approved list of Arctic ISB training courses and qualifications on its website. The database should list the minimum training and qualifications needed for each Incident Command System and field responder position and will provide a list of approved training programs to meet the requirements.

The OSRP should require an analysis of the environmental consequences of using ISB (e.g., examine the net environmental benefit of using ISB) and provide specific guidance on when ISB is not an effective response tool and when oil spill prevention measures should be implemented to avoid a spill from occurring.

Rationale: Interior Department regulations do not require any specific standards for Arctic ISB equipment or training. ISB is an important oil spill response tool for the Arctic, but Interior and the USCG do not require a minimum amount of ISB equipment or training for Arctic operations. Sufficient stock piles of in-region ISB equipment are needed in the Arctic to ensure that equipment is available at the scene and that the ISB response will not be impeded by logistical delays.

Arctic offshore field tests to verify spill response tactics and strategies prior to OCS operations

Proposal: A requirement to conduct Arctic offshore field tests to verify spill response tactics and strategies described in an OSRP prior to OCS operations should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254. The requirements should address the following key elements:

- To verify that Arctic spill response techniques, equipment, and methodologies described in the OSRP will be effective and are the best available technology for use in the Arctic environment, OSRP holders should plan for and conduct field tests prior to conducting OCS operations.
- Field tests should be conducted in the environments where operations are planned and in areas where a spill from those operations could reach.
- Field tests should include a test of all mechanical and ISB equipment (if ISB has been determined to be environmentally beneficial), and a test of dispersant application logistics (if dispersants are planned and have been proved to be environmentally beneficial and safe to subsistence resources and marine species).
- The field tests should use nontoxic oil spill simulant materials to test efficacy of the tactics and strategies proposed.
- Field testing should verify that there are effective methods developed to remove oily debris and keep the debris from clogging skimmers.
- An OSRP holder should demonstrate that it has considered the most contemporary and region-specific research regarding various aspects of spill response readiness and recovery in adopting its response tactics and equipment, and it should examined actual oil spill response data in developing a realistic plan.
- Each tactic and strategy relied upon in an OSRP should be field-tested and verified as a viable oil spill removal strategy prior to conducting OCS operations where there is a risk of spilling significant oil.

- OSRP holders should not be allowed to rely on a tactic or strategy that has not been previously field-tested by the OSRP holder or its contracted OSRO in the area and seasons in which it plans to operate. Plans on paper *only* should not be approved; only proven field-tested tactics and strategies should be approved.
- To improve planning and transparency, the Interior Department should maintain an approved list of Arctic tactics, including information on which company or OSRO has successfully tested the tactic, when it was approved, the type of equipment required to accomplish that tactic, and the estimated oil recovery rate.

Rationale: Arctic OSRPs have been approved without requiring an operator, or the OSRO(s) it relies upon, to field-test and verify that it's proposed "on-paper" tactics and strategies are efficient and effective in the Arctic prior to commencing operations. Operators have not been required to successfully demonstrate, and verify under Arctic field conditions, that its oil spill response equipment, personnel, and tactics will be effective in Arctic conditions before the plan is approved. OSRPs are currently approved relying on assumptions about what might work in Arctic conditions. Operators are only required to field-test their plans over the course of several years, during which time the Interior Department may find the operator is unprepared, or an accident may occur before testing is complete. To ensure high levels of preparedness, plans should be field-tested and verified in advance of operations.

30 CFR § 254.42 requires field tests to be conducted during the OSRP term, but not ahead of receiving plan approval. Even then, only a few aspects are tested in a single exploration season or a few aspects are tested each year of operation, typically following USCG National Preparedness for Response Exercise Program Guidelines. However, this process results in commencing exploration or production operations prior to successful field verification. Field tests will validate response technologies and strategies and the training of oil spill responders. Increased Arctic field testing will assist in identifying system and equipment deficiencies; provide an incentive for continuous improvement; and, most importantly, aid Interior in establishing seasonal drilling limits and other prevention measures for the project, based on spill response limitations identified during the testing.

The United States Arctic Research Commission recommends Arctic field testing and training.[25]

Protection of Arctic resources of special economic, cultural, or environmental importance

Proposal: Specific standards for protection of Arctic resources of special economic, cultural, or environmental importance should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254. The requirements should address the following key elements:

- Interior should ensure that OSRPs identify Arctic resources of special economic, cultural, or environmental importance that could be impacted by the WCD oil spill trajectory.
- Interior should ensure that the OSRP provides site-specific protection strategies (geographic protection strategies) for protecting resources of special economic, cultural, or environmental importance that will protect those resources prior to oil arriving at those locations.
- Interior should require that the plan holder demonstrate that those geographic protection strategies work by field testing them, prior to drilling or operating in those areas.
- OSRP applicants should demonstrate that they have adequate pre-staged response equipment and personnel dedicated to carrying out these geographic protection strategies and that this equipment is located near the area of special economic, cultural, or environmental importance for immediate deployment.

Rationale: The Arctic is subject to severe weather, but it also sustains a variety of marine mammals and seabirds that make extensive use of its waters. Residents of Arctic communities have lived an irreplaceable way of life that has existed and endured for thousands of years. They are an integral part of the region's rich ecosystem. For many residents of the Arctic, there is a direct connection between the continued health of the marine environment and the health of their food supply, their culture, and themselves. The Interior Department must take a careful look at potential impacts to subsistence resources and show its commitment to ensuring these resources are protected.

Current regulations (30 CFR § 254.23 and 30 CFR § 254.26) requires Oil Spill Response Plans to include strategies for the protection of special economic, cultural, or environmentally important areas, but it does not establish specific performance standards for the amount, type, and location of pre-staged equipment to be dedicated to special area protection. Because the Arctic is so remote and fragile and has such cultural importance, it is critical to identify areas of economic, cultural, or environmental importance and ensure there is adequate equipment, trained personnel, and strategies dedicated to protecting those resources. This includes having adequate nearshore and shoreline capability.

Geographic response strategies, or GRSs, are Oil Spill Response Plans tailored to protect a specific sensitive area from impacts following a spill. These response plans are map-based strategies that can save time during the critical first few hours of an oil spill response. They show responders where sensitive areas are located and where to pre-stage and place oil spill protection resources, and they specify the amount of time, equipment, and personnel needed. Response tactics and strategies are identified for the selected site and are tested to ensure that the tactics and strategies are effective as well as to confirm the amount of resources needed.

The strategies serve as guidelines for the federal and state on-scene coordinators during an oil spill in the area covered by the GRS. GRSs are a great help in preplanning and can provide excellent guidance during a spill response.

While the Alaska Department of Environmental Conservation, or ADEC, has developed GRSs for many areas of the state, there are no GRS developed of ADEC's caliber for either the Chukchi or Beaufort seas. ACS, the current OSRO for the Arctic, has identified Environmentally Sensitive Areas, or ESAs, for portions of the Beaufort Sea, as well as a small number for the Chukchi Sea. Most of these sites have not been tested, and very few have pre-staged equipment.

GRS documents for the Arctic should be produced of an equivalent caliber to the GRS document produced by ADEC. They should contain the level of detail about the sensitive site and the amount of equipment and personnel needed, including the time required to deploy the strategy before the oil reaches the ESA. GRSs should be prepared for each site and should clearly explain where the equipment will come from and when it will arrive.

Arctic communities should play a major role in identifying and prioritizing important areas in both nearshore and offshore areas. Indigenous Arctic peoples have developed and maintained traditional knowledge about the environment that is essential for identifying and prioritizing areas important for their subsistence and culture and for the health of the ecosystem. Local knowledge would also prove valuable in determining safe routes and access points to these sensitive sites during a spill response.

The USCG's Incident Specific Preparedness Review, after the Deepwater Horizon blowout, identified several gaps in the protection strategies for ESAs. In addition to developing best practices for identifying sensitive areas, the report recommended that protection strategies for these areas be developed and tested and that trained personnel and adequate response resources be available to carry out those strategies.[26]

Arctic OCS seasonal drilling limitations when oil spill response is not possible

Proposal: Seasonal drilling limitation standards should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254 for periods when oil spill response is not possible in the Arctic. More specifically, Arctic offshore operations drilling through hydrocarbon-bearing zones should be limited to periods of time when the drilling rig and its associated oil spill response system are capable of working and cleaning up a spill in Arctic conditions, minus the time required to drill a relief well before ice encroaches on the drill site and the time required to clean up the spilled oil from the last day that a spill could occur.

Rationale: Drilling restrictions that limit OCS offshore operations in the Arctic to summer periods ensures there is sufficient time left in the operating season to cap a blown-out well, drill a relief well, and clean up spilled oil in open water, thereby providing a critical margin of safety in the proposed plan. Seasonal drilling restrictions, with these specific components, are not included in existing regulations.

Arctic environmental conditions—including sea ice and extreme cold—present unique challenges for oil spill cleanup operations. Routine drilling operations that extend to the very last day that it is safe to drill do not allow time to respond to a well control event. When winter conditions set in and equipment needs to be removed from the Chukchi and Beaufort seas, it becomes unsafe to stage a response in the ice, freezing conditions, and darkness. A spill in the Chukchi and Beaufort seas not contained by freeze-up, therefore, could continue unabated through the winter.

There are no specific Interior Department regulations requiring operators to follow seasonal drilling limitations for Arctic operations. Although Interior effectively applied seasonal drilling limits to Shell's 2012 Chukchi Sea OCS Drilling Project, similar limits are not imposed on all projects. For example, the Interior Department did not apply seasonal drilling limits to Shell's 2012 Beaufort Sea OCS Drilling Project, although ice sets in early there and is of the more dangerous multiyear ice type. Therefore, there is a need to establish standards that would be applied consistently across all projects.

Public and joint agency review process for Arctic oil spill response plans

Proposal: A public and joint agency review process should be added to the Interior Department's Oil Spill Response Regulations at 30 CFR § 254. The requirements should address the following key elements:

- Interior should ensure that there is a process for joint agency and public review of Arctic Oil Spill Response Plans before approving them.
- All Arctic OCS exploration and production OSRPs should be made available for a 60-day public review and comment period.
- Public notice should be provided in the *Federal Register* and sent directly to all impacted stakeholders, which at a minimum should include: the affected local government (NSB and the Northwest Arctic Borough); state government (ADEC, Alaska Department of Fish and Game, Alaska Department of Natural Resources); federal government (National Oceanic and Atmospheric Administration, or NOAA, U.S. Fish and Wildlife Service, U.S. Geological Survey, or USGS, Environmental Protection Agency, or EPA, and USCG); and tribes.
- Interior's Bureau of Safety and Environmental Enforcement, or BSEE, should issue a decision document. Interior's finding document would explain how the plan-holder has met each requirement of 30 CFR § 254,

responded to public comments, describe improvements required to enhance response efficacy, explain mitigation required to reduce the risk of an oil spill, and list oil spill prevention measures required when oil spill response is not possible.

Rationale: Currently, there is no Interior Department requirement in the CFR requiring Interior to conduct a public and joint agency review of Arctic OCS exploration and production OSRPs. While Interior has provided opportunities for public and joint agency review on some projects, the review process has been inconsistent and unpredictable, and, under some administrations, it does not occur at all. Because the Interior Department does not issue a decision document, the public and other agencies do not have the tools necessary to understand Interior's decision and how it complies with the 30 CFR § 254 requirements.

There is a heightened, broad public interest in oil spill response by academics, nongovernmental organizations, local government, and other federal agencies. OSRPs are complex, extensive documents that can benefit from public and joint agency review. Unlike most federal plans and permits, there is no formal public review or interagency review and comment period established, except through the ability to comment via the Exploration Plan.

The National Commission on the BP Deepwater Horizon recommended joint agency and public review of OSRPs and that the plans be made available to the public once they are approved. The recent joint agency review process resulted in improvements in Shell's OCS OSRP for the Chukchi Sea, and this process should be continuously improved and applied to future plans.

Arctic OCS oil spill trajectory analyses and mapping standards

Proposal: Improved requirements for Arctic oil spill trajectory analyses and maps should be included in the Interior Department's Oil Spill Response Regulations at 30 CFR § 254, as follows:

- An oil spill trajectory analysis should be completed to examine the potential for oil impacts resulting from the WCD under an average-weather scenario and an adverse-weather scenario.
- Arctic oil spill trajectories should be developed to reflect the maximum distance that oil can be expected to travel under various oil removal scenarios, including no response; 1-5% oil removal (based on low recovery rates in icy conditions); and 10-20% oil removal (best-case recovery rates in temperate water), and to depict nearshore and shoreline impacts. Oil spill trajectories assuming higher oil removal efficiencies can be submitted if higher oil spill removal efficiencies are technically supported.
- Arctic oil spill trajectories should be developed to examine a realistic range of potential Arctic weather conditions that could occur, including adverse-weather scenarios based on at least 10 years of historical data, preferably 20 years of data, if available.
- Adverse-weather trajectories should also be completed to assess oil impacts during periods when oil spill response is not possible. Worst-case adverse weather should be examined, and estimates should be included on the frequency and likelihood to encounter adverse weather.
- Trajectory modeling should be run using a computer model approved by NOAA and capable of modeling subsurface and surface oil movement in ice-infested waters.
- All oil spill trajectories should include an estimated oil spill thickness, degree of emulsification, and amount of ice that will be present in order to more realistically assess possible response options.
- Trajectory models should use ice, wind, and current data for the period of time when the spill may continue.

- Resource sensitivity maps should be provided for each area that could be exposed to oil pollution over at least a 365-day period after the spill.
- All trajectories should reflect the maximum distance from the rig/facility that oil could move in a time period during which it's reasonably expected to persist in the environment, including an overwintering trajectory of the oil as it travels in ice or is carried by currents.

Rationale: Spill response planning should ensure that there is adequate equipment and trained personnel available to remove a WCD in Arctic conditions. Because of the remote location and potential weather and logistical challenges, it is necessary to ensure that Arctic oil spill response resources needed to remove the oil are located in the region to avoid delaying response. Estimating the amount of oil in a WCD, assessing where the oil may be expected to travel, how much equipment an operator needs to remove the spill, and establishing oil removal benchmarks are all important elements of Arctic Oil Spill Response Planning.

Interior's regulations should be revised to require oil spill trajectories that examine the path of unrecovered oil for at least one year after the spill and over a wide range of weather conditions and recovery rates. This analysis will assist planners in determining how many spill removal task forces are needed, where to pre-stage response equipment, and which sensitive areas may be at risk.

OSRPs are required to have a worst-case oil discharge scenario that includes a trajectory analysis showing the maximum distance that oil could travel from the spill source while it persists in the environment, and the offshore and coastal areas that could be affected.[27] It is important for oil spill trajectories to examine realistic oil recovery and a realistic range of potential Arctic weather conditions that could occur, including adverse-weather scenarios. Currently, Arctic OCS OSRPs are based on oil spill recovery planning estimates that have not been demonstrated or proved in field conditions.

Trajectory models used for oil spills in temperate waters are inadequate for modeling oil in ice because they require detailed wind and current data that are not available for many areas of the Arctic,[28] and they do not include the trajectory interference caused by ice that can divert oil or cause oil to be trapped in or under the ice. The capability to predict ice dynamics at a scale useful for trajectory models is limited.[29] While a joint industry project is working to improve trajectory models used for oil spills in ice-infested waters,[30] there has been little advancement in this area.

Realistic oil spill trajectory estimates will allow more accurate identification of offshore and coastal areas that could be affected and ensure that plans are put into place to protect these areas in the event of a spill. Historically, Interior has only required operators to submit 30- to 90-day oil spill trajectories, and those trajectories assume that the oil spill can be cleaned up at rates that have not been demonstrated in field conditions. These trajectories are insufficient for both short- and long-term Oil Spill Response Planning.

Arctic OCS oil recovery storage standards

Proposal: Improved requirements for Arctic oil recovery storage should be included the Interior Department's Oil Spill Response Regulations at 30 CFR § 254, including:

- A sufficient amount of on-site ("in-region") recovered oil storage capacity, including both primary and secondary storage capacity, sufficient to recover the amount of spilled oil without impeding spill response operations.

- A sufficient amount of pump capacity and capability to transfer recovered viscous and emulsified oil and water mixtures.
- Storage volumes that account for emulsification, free water collection, and remote logistical access and weather delays.
- Arctic storage systems capable of heating and separating oil-water emulsions and decanting water to maximize oil recovery and storage.

Rationale: Interior Department regulations do not currently include minimum storage standards for Arctic operations. The remote location of drilling operations, limited logistical access and adverse weather delays can preclude arrival of additional storage. Inadequate storage can impede or halt oil spill response recovery operations and is a critical component in overall oil spill response system effectiveness.

Arctic OCS oil removal and Arctic oil removal benchmarks

Proposal: An enhanced method for calculating Arctic oil removal and Arctic oil removal benchmarks should be included in the Interior Department's Oil Spill Response Regulations at 30 CFR § 254. The requirements should include that:

- Interior develop an enhanced method for calculating oil removal based on encounter rate modeling. The encounter rate model should include Arctic spill response operating parameters such as ice and adverse weather.
- OSRPs establish benchmarks for oil spill removal. Oil removal should be given the highest priority over other spill response methods (e.g., dispersant application) that merely distribute oil in the water column, thereby leaving it in the marine environment.
- Both mechanical and ISB oil removal estimates be based on previous, actual oil spill removal estimates achieved during an actual oil spill.
- The OSRP include computations showing the expected daily oil removal capability based on the expected mechanical response efficacy.
- The OSRP also examine the incremental oil removal capability that might be achieved where ISB is applied either alone or in combination with mechanical recovery.
- Based on these computations, benchmarks for oil removal be established in the OSRP, and a monitoring system be developed and described in the plan to examine, on a daily basis, the actual oil removal as compared to the expected benchmarks. These oil removal benchmark estimates should be integrated into the trajectory modeling to provide a more realistic assessment of the amount of oil that might actually be removed from the environment.
- The OSRP holder be required to report daily to incident command on its progress in achieving the oil removal benchmarks.

Rationale: The current method for calculating oil removal efficiencies is inaccurate, as evidenced by the Deepwater Horizon spill. An enhanced method for calculating oil removal should be based on encounter rate modeling that includes spill response operating parameters such as ice and adverse weather. The USCG's Deepwater Horizon Incident Specific Preparedness Review recommended a review of effective daily recovery capacity (EDRC) calculations and planning standards, and that this review should ensure that adverse weather considerations are included as part of the planning standards.[31]

Arctic OCS dispersant-use guidelines

Proposal: Arctic dispersant-use guidelines should be included in the Interior Department's Oil Spill Response Regulations at 30 CFR § 254. Dispersant use should be co-managed by the EPA and Interior. Interior should establish limitations regarding the terms, conditions, and circumstances in which dispersant use would be allowed in Arctic waters.

At a minimum, dispersant use in the Arctic should not be conducted until the Operator has proven that dispersant application is nontoxic, not harmful to subsistence resources, is acceptable to the local community, and has been proven to result in a net environmental benefit.

Dispersants, if applied, should be carefully monitored.

Vessel and aircraft dispersant systems should be additional and separate from vessels and aircraft required for mechanical recovery and ISB operations, so that dispersant application (if used) does not hinder the potential to use mechanical or ISB methods in other areas of the spill slick.

Rationale: Dispersants came under scrutiny in response to extensive surface and subsea application during the Gulf of Mexico oil spill response. Work is still needed to establish limits on dispersant use and to limit its application to periods when it is more environmentally beneficial than mechanical or ISB oil removal methods or than allowing oil to persist in the environment. The National Oil Spill Commission recommended that dispersant testing protocols for product listing or preapproval be periodically reviewed and updated and that the preapproval process be modified "to include temporal duration, spatial reach, and volume of the spill."[32]

Historically, dispersants were viewed as having the potential for only limited success in the Arctic due to the lack of natural mixing energy caused by the dampening effects of ice, tendency for oil to become viscous at low temperatures, and biological impact concerns regarding chemical toxicity and the potential for bioaccumulation in subsistence foods. After the Deepwater Horizon well blowout additional scientific work[*] began to examine the potential to use dispersants in response to a subsea Arctic well blowout.

Dispersant-use guidelines for Alaska's Arctic are over two decades old and do not incorporate current technology and scientific data. The Alaska Regional Response Team is currently revising Alaska's dispersant-use guidelines.

Dispersant application can work at cross-purposes with mechanical and ISB oil removal by distributing oil through the water column and making it more difficult to recover. The decision to apply dispersants will require a thorough scientific and technical assessment prior to use in the Arctic.

The United States Arctic Research Commission recommends the effects of dispersed oil on Arctic ecosystems be defined, including assessments of the toxicity of dispersed oil and dispersants on benthic flora and fauna, marine mammals, and seabirds.[33]

Oil spill recovery calculations and minimum equipment requirements for the Arctic OCS

Proposal: Oil spill recovery calculations and minimum equipment requirements should be included in the Interior

* The University of Alaska, Shell Oil, the Barrow Arctic Research Center, and the Joint Industry Programme, or JIP, have been conducting laboratory studies to examine dispersant applications methods for the Arctic and the biologic impact of such application.

Department's Oil Spill Response Regulations at 30 CFR § 254 based on enhanced encounter rate modeling. Interior should require that:

- Oil spill recovery calculations and minimum equipment requirements be based on Arctic encounter rate modeling, and the effectiveness of the entire spill response system be examined. This method would replace the existing effective daily recovery capacity, or EDRC, that examines only de-rated skimming pump capacity (skimming pump capacity reduced to 20%).
- The Arctic encounter model be approved by Interior and include Arctic encounter rate limitations, including ice, adverse weather, and logistics limitations, and examine mechanical and ISB options.
- The amount of mechanical response equipment be sufficient to clean up the entire spill.
- The amount of ISB equipment be sufficient to clean up the entire spill in the event that mechanical equipment is rendered ineffective.

Therefore, minimum equipment requirements for the Arctic will include providing both sufficient mechanical and ISB equipment to use either technique alone, or in combination, providing responders with a complete, optimized tool kit.

Rationale: Operators are currently required to calculate the amount of equipment needed to respond to an oil spill for 30 days using the EDRC calculation.[34] The EDRC calculation is meant to account for inefficient oil removal due to "available daylight, sea state, temperature, viscosity, and emulsification of the oil being recovered,"[35] by reducing the estimated skimmer pump capacity to 20% of what the manufacturer suggests.

The EDRC oil spill response calculation does not take into account inefficiencies due to the inability of equipment to encounter oil in the presence of ice and adverse weather common in the Arctic, or inefficiencies in the entire spill response system.[36] The "encounter rate" is how often equipment actually reaches oil that is able to be removed. Equipment may not be able to reach oil or remove it if precluded by ice, weather, waves, or other factors that limit the amount of oil encountered and recovered. In the Arctic, oil spill response is limited by the weakest link in the chain, which may be the connection, hose, or fitting that can readily become frozen or clogged with ice, requiring significant system downtime to clear, repair, or thaw the impediment.

As shown by the 2010 Deepwater Horizon oil spill, the current oil spill response calculation underestimates the amount of oil spill response equipment needed, even in temperate waters. Less than 3% of the oil was recovered using mechanical, skimming, and boom response equipment,[37] even though BP had more than three times the required amount of oil spill response equipment on-site and skimming.[38] The most effective tool at capturing oil in the Gulf of Mexico was the capping stack that eventually contained 17% of oil spilled.[39]

In any large oil spill, the oil rapidly spreads to form a thin layer on the water surface. The problem is worse for well blowouts, where average oil slick thickness may be in the range of 0.001 mm to 0.01 mm. Oil must be thickened to at least 2-5 mm to sustain a burn, and booming is not possible with current boom technology above 30-40% ice.

For either mechanical recovery or ISB, boom must be used to concentrate the oil for effective removal. To avoid entrainment losses, most conventional containment boom must be towed at a speed of less than 1 knot, which severely limits the rate at which the slick is encountered.[40]

ISB will likely be an important spill response tool in the Arctic. However, burning equipment is not currently part of the oil spill response calculation, and Interior does not currently require operators to demonstrate a minimum amount of burning equipment.

While the Interior Department hired contractors Genwest and SpillTec to make recommendations and develop an improved model to more accurately estimate the EDRC, including encounter rate and other factors, the revised oil spill response calculation will apply to temperate waters only and will not include additional inefficiencies encountered in the Arctic, such as ice.[41] Therefore, more work is needed to develop an Arctic-specific model that includes ice and other Arctic conditions.

Arctic OCS mechanical response equipment and training standards

Proposal: Mechanical response equipment and training standards for the Arctic should be included in the Interior Department's Oil Spill Response Regulations at 30 CFR § 254, including:

- Arctic mechanical response equipment and training standards should be established to ensure there is sufficient in-region capability to respond to the oil spill, including sufficient Arctic-grade equipment and personnel trained to operate that equipment.
- Personnel should have training and qualifications in Arctic mechanical response and deployment and operation, and vessel captains and pilots should have experience navigating in the Arctic.
- The OSRP should include a plan to cascade in additional equipment by water, air, and/or land to replenish expendable boom, skimmers, hoses, connections, PPE and other supplies (out-of-region equipment). Any equipment that cannot be mobilized to the Arctic by water, road, or air within 30 days should be part of the in-region response equipment.
- The OSRP should include evidence that the plan-holder either owns, or has under contract, sufficient in-region Arctic equipment and personnel trained and qualified to operate that equipment.
- Arctic-grade equipment should include, but not be limited to: Arctic-grade skimmers, ice-boom, viscous oil pumps, winterization enclosures and heating systems to protect equipment and prevent freezing, systems to thaw frozen equipment, Polar Class vessels (icebreakers, storage and recovery vessels), shallow draft vessels capable of operating in ice-infested water and able to provide nearshore response access, landing craft capable of accessing remote shores where docks are not present, and cold-weather PPE.

Rationale: Arctic conditions—including broken ice, freezing temperatures and dense fog—can affect the efficiency of mechanical response equipment and personnel. The presence of ice and debris in marine spill response can reduce the efficiency of response operations by creating hazardous working conditions or conditions that impair or damage mechanical response equipment.

Slush ice, for example, can clog skimmers, and cold temperatures can freeze the hoses used to move the oil to a storage container, making the skimmer unusable for hours or days until thawed. Operators must demonstrate its spill response equipment is capable and personnel are trained to work in Arctic conditions. This equipment must be readily available, in-region. Waiting for additional or Arctic-grade equipment to arrive could unnecessarily delay spill response.

Interior Department regulations do not currently require any specific standards for Arctic mechanical response equipment or training. ACS, the current primary OSRO in the Arctic, does not have a full, robust system of Arctic-grade mechanical response equipment. While ACS has a few Arctic-grade skimmers, a couple of viscous oil pumps, and a tested ice-boom, most of its inventory is not Arctic-grade. ACS has no ice-class vessels, and its fleet is removed from the Beaufort Sea within the first week of October, and it does not re-enter the ocean until the ice subsides again in July. This means the existing offshore response capability is limited to less than four months per year (July-early October). Some operators are proposing to supplement ACS's equipment with additional Arctic-grade equipment, although some OCS operators currently operating in the Arctic have approved OSRPs that do not.

Canada, by comparison, requires that an operator demonstrate, including field exercises in Arctic conditions, that its oil spill response equipment and personnel are trained and equipped to work in the Arctic. More specifically, the Canada National Energy Board, Filing Requirements for Offshore Drilling in the Canadian Arctic require[42] an operator to describe in its application the "key response strategies and methods for spill containment, monitoring, tracking recovery, and clean-up on surface water, the subsurface, shoreline, ice, and ice infested waters. For each response method, describe operational limitations (response gaps) caused by unique Arctic environmental conditions such as wind, waves, ice, temperature, visibility, and daylight.

"Criteria and procedures to monitor the effectiveness of each response strategy and method.

"Training qualification requirements, or competency measures, for personnel and the proposed scope and frequency of field practice exercises for oil spill countermeasures under Arctic conditions.

"The scope and frequency of Arctic-based predrilling and operational spill-response exercises intended to test response and further verify effectiveness of response strategies, methods, and emerging technologies."

WCD blowout flow rate and total volume estimation methods for the Arctic OCS

Proposal: WCD blowout flow rate and total volume estimation methods for the Arctic should be included in the Interior Department's Oil Spill Response Regulations at 30 CFR § 254.

Worst-case blowout rates should be based on offset well data and be representative of highest predicted fully unobstructed, open-orifice, maximum Absolute Open Flow Potential, or AOFP, of the well, persisting for at least 60 days or the period required to drill a relief well, if longer than 60 days.

Where there is no analogous well data to develop a site-specific, well-specific WCD blowout flow rate and total volume estimate, the plan should adopt a WCD volume equal to at least 61,000 barrels of oil per day, or bopd, for Chukchi Sea wells and 25,000 bopd for Beaufort Sea wells.

Rationale: The Interior Department only requires companies to describe the response to a WCD scenario for 30 days. As recent experience demonstrated in Australia (2009) and the Gulf of Mexico (2010), OCS well blowouts were not contained within 30 days. Because relief well and capping operations in the Arctic may be remote, logistically challenging and subject to ice and freezing conditions, and take longer than well control in other areas of the United States, it is recommended that the WCD be based on 60 days rather than 30 days.

Additionally, both the Australia (2009) and Gulf of Mexico (2010) well application, under predicted the amount of oil that might be spilled in its Oil Spill Response Plan. To ensure that the WCD is accurately assessed and planned for in an Arctic well application, the worst-case blowout rates should be based on offset well data and be representative of highest predicted fully unobstructed, open-orifice, maximum AOFP of the well, persisting for at least 60 days or the period required to drill a relief well, if longer than 60 days.

In the absence of site-specific, well-specific data, the operator should be required to use Interior's very large discharge, or VLD, well blowout estimates for the Arctic.

In 2011, the Interior Department estimated that a VLD of oil from an exploration well in the Chukchi Sea OCS Planning Area could be as high as 61,000 bopd, declining though the first 30 days of flow as the reservoir is depressurized by 1,000 pounds per square inch.[43] Interior estimated that the pressure decline reduces the flow rate to 18,800 bopd by day 90, with a cumulative oil spill of 2,474,000 barrels over that 90 day period. Interior estimates that if the blowout can be stopped in 39 days by drilling a relief well that the total spill would be 1,384,000 barrels.

In 2011, the Interior Department estimated that an oil spill from an exploration well in the Beaufort Sea OCS Planning Area could be as high as 16,000 bopd,[44] with a cumulative oil spill of 480,000 barrels over a 30-day period, assuming a relief well could be drilled in 30 days at Shell's proposed drilling location. If the spill continues for 90 day, the spill volume would increase to 1,440,000 barrels.

The Interior Department has not developed a VLD estimate for a generic Beaufort Sea well. Based on historical well data in this area, and experience of engineers who have worked in this area, a 25,000 bopd estimate should be used.*

* The Beaufort Sea blowout estimate of 25,000 bopd was recommended by Harvey Consulting LLC.

Endnotes

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