



## Arctic Regulations Benefit Cost Analysis

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## Acronyms and Abbreviations

AEWC	Alaska Eskimo Whaling Commission
BBL	Barrels of Oil
BBBL	Billions of Barrels of Oil
BBOE	Billion Barrels of Oil Equivalent
BCA	Benefit Cost Analysis
BE	Biological Evaluation
BO	Biological Opinion
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy, Management, Regulation, and Enforcement
BOP	Blow Out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Conflict Avoidance Agreement
CGOM	Central Gulf of Mexico
DOI	Department of the Interior
E&A	Exploration and Appraisal
EA	Environmental Assessment
EGOM	Eastern Gulf of Mexico
EIS	Environmental Impact Statement
EP	Exploration Plan
EPA	Environmental Protection Agency
ERC	Environmental Research Consulting
ESA	Endangered Species Act
ESI	Environmental Sensitivity Index
ESPIS	Environmental Studies Program Information System
ESRP	Estimated Recovery System Potential
EU	European Union
GOM	Gulf of Mexico
HEA	Habitat Equivalency Analysis
IHA	Incidental Harassment Authorization
ISB	In Situ Burning
ISER	Institute of Social and Economic Research

ITA	Incidental Take Authorization
JIP	Joint Industry Program
LMRP	Lower Marine Riser Package
LOA	Letter of Authorization
MMPA	Marine Mammal Protection Act
MSD	Marine Sanitation Device
NCP	National Contingency Plan (Oil and Hazardous Substances Pollution)
NEB	National Energy Board
NEBA	Net Environmental Benefit Analysis
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NRDA	Natural Resource Damage Assessment
NSB	North Slope Borough
O&M	Operations and Maintenance
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECM	Offshore Environmental Cost Model
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
OSR	Oil Spill Response
PSO	Protected Species Observer
PV	Present Value
RIA	Regulatory Impact Analysis
RRT	Regional Response Team
SEIS	Supplemental Environmental Impact Statement
SSRR	Same Season Relief Rig
TAPS	Trans Alaska Pipeline System
TCF	Trillion Cubic Feet
USFWS	U.S. Fish and Wildlife Service
VLOS	Very Large Oil Spill

WCD	Worst Case Discharge
WGOM	Western GOM

## Executive Summary

The Office of Information and Regulatory Affairs (OIRA), a division of the Office of Management and Budget (OMB) is tasked with the review of new rules promulgated by regulatory agencies. A series of executive orders has dictated that the benefits of new regulations not be outweighed by the costs of compliance, and not ultimately serve to stifle innovation, creativity or the efficient function of markets. It is through this lens that the OIRA reviews an agency's regulatory impact assessment (RIA) of its own proposed rules to ensure that draft regulations align with the presidential directives set forth in these executive orders.

ENVIRON has prepared this report to provide analysis to inform the OIRA's review of the forthcoming draft regulations promulgated by the Department of Interior (DOI) governing oil and gas exploration activities in the Alaska OCS (Arctic Regulations). Included below is a benefit-cost analysis (BCA) of three elements that may be included in the draft Arctic Regulations: (1) a same season relief rig (SSRR) requirement; (2) a seasonal limitation on drilling; and (3) a requirement that an operator demonstrate capacity to respond to 100 percent of its Worst Case Discharge (WCD) with mechanical recovery tools alone. The results of this analysis illustrate a substantial disconnect between these rule elements and the presidential directives outlined above.

The OIRA should apply its authority under Executive Order 12866 to return the draft Arctic Regulations to the DOI if any of the three elements analyzed in this report are present in the actual rule.

### Same Season Relief Rig

A SSRR requirement would direct all Arctic operators to contract a second rig capable of drilling a relief well and maintain that rig in proximity to the theater such that the rig would be available to drill a relief well prior to the onset of winter ice. Over a twenty-year exploration and appraisal phase, the present value of a SSRR requirement is nearly 3.2 billion dollars in cost to the lessee. In contrast, the benefits of a SSRR requirement over the same time period are estimated at only 791 million dollars.

The relatively minor benefits associated with a SSRR requirement are due in part to the low probability of a well blowout in the shallow exploration and appraisal wells being pursued in the U.S. Arctic OCS. The nominal benefits associated with a SSRR requirement can also be explained by the substantial barrier and control technologies that operators have in place both to mitigate the risk of a loss of well control, as well as to respond if such an event occurs. There is a hierarchy of technologies and responses that, depending on the situation, could provide not only a faster, more environmentally protective response than a relief well, but one that is more cost efficient. The availability and use of other technologies to stop a loss of well control is reinforced by U.S. government records; since 1971 there has not been a single blowout event in the U.S. controlled by a relief well.

Given the relative costs and benefits of a SSRR requirement, the codification of such a requirement cannot be supported. Further, the modest benefits from such a requirement could be preserved (and potentially exceeded given advancing technologies) if the U.S. adopted a performance standard calling for SSRR equivalency.

## **Seasonal Drilling Limitation**

A seasonal drilling limitation refers to the requirement that an Arctic operator cease drilling into hydrocarbons at a prescribed date calculated based on the anticipated onset of winter ice. Over a twenty-year exploration and appraisal phase, the present value of such a seasonal limitation requirement is 6.8 billion dollars in cost to the lessee. Such a condition also results in losses to the nation in the amount of 89 billion dollars. In contrast, the benefits of a seasonal drilling limitation are estimated at 301 million dollars over the same period.

The rationale underlying the seasonal drilling limitation is that it is necessary to ensure that an operator has time to use a SSRR to drill a relief well prior to the onset of winter ice. Yet, as discussed in the preceding section, drilling a relief well is not the only method, or most efficient method an operator could use to control a late season blowout. However, even where the assumption is made that a relief well is the only (or preferred) response, the benefits gained from imposing a blackout window are minimal. Regulations already require that an operator submit a Critical Operations Curtailment Plan (COCP) as a part of its Exploration Plan (EP) to demonstrate that it has a plan to curtail operations in response to emerging hazards in the environment. Further, in other areas where the BOEM regulates offshore oil and gas activities, including the Gulf of Mexico, the agency does not regulate prescribed end of season dates based on seasonally re-occurring environmental threats, such as hurricanes.

Given the relative costs and benefits of a seasonal drilling limitation, the codification of seasonal drilling limitations cannot be supported. Whether and if an operator is required to end its drilling season should be driven whether the assets the operator is bringing to the theater are capable of safely drilling for the period of activity the operator has planned.

## **100% Mechanical Recovery Capacity**

A 100 percent mechanical recovery capacity requirement refers to the requirement that an operator demonstrate in its Oil Spill Response Plan (OSRP) that it has mechanical recovery assets available to respond to its entire WCD using those assets alone, as opposed to other tools such as In Situ Burning (ISB) or dispersants. Currently, operators in the Chukchi and Beaufort Seas are required to meet this requirement due to the North Slope Subarea Contingency Plan, which is a part of the Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases.

The cost of this requirement over a twenty-year exploration and appraisal phase is 119 million dollars to lessees. There are no environmental or social benefits attributable to this requirement if you compare it with an approach that allows an operator to develop its OSRP using the Net Environmental Benefits Analysis (NEBA) approach that is applied in other U.S. OCS regions and around the world.

Requiring an operator to maintain mechanical assets sufficient to account for 100 percent recovery of its WCD in proximity to the drill site is inefficient and may result in additional impacts to the environment. This requirement significantly increases the number of vessels an operator must maintain in theater to support its drilling activities. With additional vessels comes the potential for additional environmental impacts. These impacts cannot be justified considering that in the event of an actual oil spill an emergency response team may determine the best



option for responding is not with mechanical recovery tools, but with ISB or dispersants. Depending on spill characteristics and metocean conditions, dispersants and ISB are more effective at cleaning up an oil spill than is mechanical recovery equipment.

Given the relative costs and benefits of a 100 percent mechanical recovery capacity requirement, the codification of such a requirement cannot be supported. Any Arctic Regulations dealing with oil spill response should allow operators to apply a NEBA approach and account for all appropriate response tools.

# 1 Introduction

The Arctic is thought to hold significant untapped oil and gas resources. The Federal Government has estimated that the amount of undiscovered technically recoverable resources in the Beaufort and Chukchi Seas of the Outer Continental Shelf (OCS) is 23.6 billion barrels of oil and 104.41 trillion cubic feet of natural gas.<sup>1</sup> The United States has much at stake in exploring and developing Arctic resources. The financial benefits to the nation of Arctic OCS development are substantial, not to mention the broader impact of achieving increased energy independence.

The Department of Interior (DOI) is currently engaged in the rulemaking process for new regulations governing oil and gas exploration activities in the Alaska OCS (Arctic Regulations). Prior to the public release of the draft Arctic Regulations, the Office of Information and Regulatory Affairs (OIRA), a division of the Office of Management and Budget (OMB) conducts a review, pursuant to Executive Order 12866, which establishes a set of governing principles for effective and efficient regulation. As part of its regulatory review, the OMB reviews the regulatory impact analysis (RIA) provided by the agencies, which includes an estimate of the benefits and costs (quantitative and qualitative) of the proposed regulations and any identified alternatives to the regulatory actions proposed.

This report provides an independent benefit-cost analysis (BCA) meant to inform the OMB's review of the draft Arctic Regulations. Although the draft regulations have not yet been made public, ENVIRON has conducted a BCA on three elements that it anticipates may be included in the draft Arctic Regulations. These elements are:

- 1) Same Season Relief Rig: There is no existing OCS regulation that requires an operator to have a same season relief rig under contract. However, in 2011, Shell detailed its same season relief rig (SSRR) capacity in its Exploration Plan (EP), which BOEM approved. It is believed that the DOI is considering a requirement in the draft Arctic regulations that all U.S. Arctic OCS oil and gas drilling operators have a second relief rig under contract and available to drill a same season relief well.
- 2) Seasonal Drilling Limitation: There is no existing OCS regulation that limits the duration of an operator's season based on seasonal weather events. U.S. Arctic OCS lease stipulations also do not include seasonal limits on drilling activities. However, in its 2011 approval of a Shell EP for drilling in the Chukchi Sea,<sup>2</sup> the DOI imposed a hydrocarbon blackout date beginning September 24<sup>th</sup> of each year, after which time no drilling into hydrocarbons was permitted. It is believed that the DOI is considering including a similar requirement in the Arctic regulations.

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<sup>1</sup> Bureau of Ocean Energy Management (BOEM). 2011. "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf," available at [http://www.boem.gov/uploadedfiles/2011\\_national\\_assessment\\_factsheet.pdf](http://www.boem.gov/uploadedfiles/2011_national_assessment_factsheet.pdf). Estimates are based on Table 1, Page 3, "Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)."

<sup>2</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management, Alaska Outer Continental Shelf Region David W. Johnston, Regional Supervisor, Leasing and Plans, letter to Ms. Susan Childs, Shell Gulf of Mexico Inc., December 16, 2011.

- 3) 100 Percent Mechanical Recovery Capacity: There is no existing OCS regulation that requires an operator to demonstrate that it has the capacity with mechanical recovery assets to 100 percent of its Worst Case Discharge (WCD). (Operators are required to demonstrate that they can respond to 100 percent of their WCD, but not strictly with mechanical recovery assets.) However, operators in the Alaska OCS are currently required by BSEE to demonstrate capacity to respond to 100 percent of their estimated WCD with mechanical recovery assets. It is believed that the DOI is considering including a similar requirement in the Arctic Regulations.

## 1.1 OMB's Obligation to Consider Costs and Benefits

OMB's regulatory review process is guided by Executive Order 12866, which sets forth the broad principles agencies are required to adhere to when proposing new regulations. The order provides that agencies,

*shall assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, **propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.***<sup>3</sup>

Pursuant to this guidance, the agency proposing a regulatory action provides the OMB with a RIA, which describes and justifies the proposed regulatory action, and includes a BCA. As part of the BCA, agencies are required to assess a range of regulatory alternatives as well as non-regulatory solutions before proposing a regulatory action. If OMB's review of the agency's BCA indicates that none of the proposed regulatory configurations provides an environmental or social benefit that justifies the cost of executing the new rule, OMB has the authority to return the proposed rule to the agency for further consideration.<sup>4</sup>

## 1.2 The Executive Preference for Performance-Based Regulation

Executive Order 13563, which affirms and expands upon the regulatory principles established by Executive Order 12866, states that regulations should, "*to the extent feasible, **specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt.***"<sup>5</sup> This preference for performance-based regulation was reinforced most recently in the recommendations put forth in the Deepwater Horizon report to the President following the Macondo incident in 2010, which stated:

*"The Department of the Interior should develop a proactive, risk-based performance approach specific to individual facilities, operations and environments, similar to the 'safety case' approach in the North Sea."*<sup>6</sup>

Performance-based regulation is outcome driven. The regulator sets goals and objectives to be achieved and allows room for a variety of avenues to compliance, rather than prescribing

<sup>3</sup> Exec. Order No. 12866 Section 1(b)(6), emphasis added.

<sup>4</sup> EO 12866, Section 6(b)(3).

<sup>5</sup> EO 13563, emphasis added.

<sup>6</sup> Deepwater Horizon: The Gulf Oil Disaster and the Future of Offshore Drilling" National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Report to the President, 2011. Pg. 252.

methods, practices, or technologies that must be used to achieve a goal or objective. Performance-based regulation tends not to constrain markets or technological innovation, but rather provides incentives for market mechanisms to spur technological advances, bringing about operational and environmental improvements efficiently as companies strive to compete.

### 1.3 International Regulatory Considerations

The governments of Norway, Canada, Greenland, and Russia have all overseen oil and gas exploration in their Arctic waters. Executive Order 13609, titled “Promoting International Regulatory Cooperation” notes the value of examining foreign regulatory approaches to “shared challenges involving health, safety, labor, security, environmental, and other issues,” as well as the ability of international regulatory cooperation to “reduce, eliminate, or prevent unnecessary differences in regulatory requirements.”<sup>7</sup>

Norway has a long history of offshore exploration in the Arctic (with first wells being scoped in the early 1970s), and the most extensive history of experimentation and evolution of regulatory regimes to address these activities. Since the 1980s, Norway has been working to develop a coherent, integrated legal framework for regulating health, safety, and environment in the conduct of oil and gas operations. The Norwegian approach has been to develop and codify standards and functional requirements, placing the burden of how those thresholds and benchmarks are met on operators—in broader terms, Norway has shown a commitment to performance-based regulation. As a result, operators develop and apply an “internal control” system for reducing risks and preventing and responding to accidents, reflecting a “sound health, environment, and safety culture.”<sup>8</sup>

As pointed out in the 2011 “Arctic Offshore Drilling Review” conducted by the Pembina Institute on behalf of the Canadian National Energy Board (NEB), Norway is not unique among Arctic states in adopting risk and performance based approaches to permitting and regulation of activities in the Arctic OCS.<sup>9</sup> Denmark, Canada, and Greenland have all adopted elements of performance-based regulation for drilling requirements, well control, and independent verification and oil spill response. Although not an Arctic OCS nation, Australia has also adopted a performance-based approach to legislation governing offshore exploration and production.

As part of its analysis, the Pembina Institute conducted a comparative review of the regulatory regimes of four countries with Arctic offshore drilling operations.<sup>10</sup> Overall, the analysis found that only the United States relies almost exclusively on prescriptive approaches to regulate offshore drilling and production. The U.K., Greenland, and Norway utilize an almost entirely risk/performance based set of protocols, while Canada employs a hybrid of the two. Figure 1 illustrates each country’s protocols with examples following the Pembina analysis.

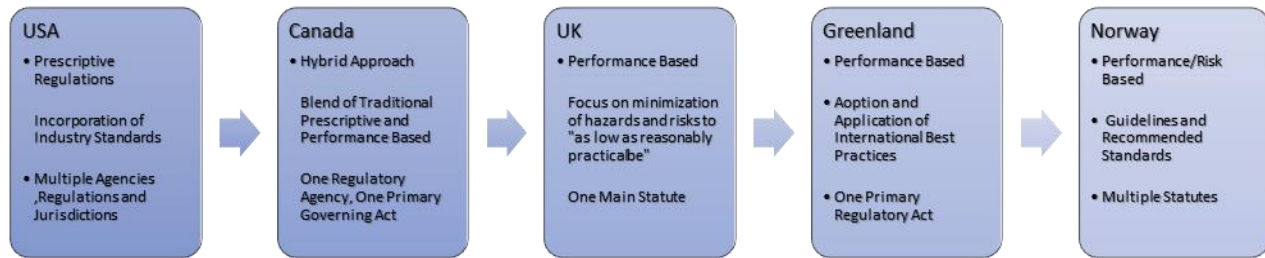
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<sup>7</sup> EO 13609.

<sup>8</sup> Lindøe, P.H., et. al. 2011. “Empowered Agents or Empowered Agencies? Assessing the Risk Regulatory Regimes in the Norwegian and U.S. Offshore Oil and Gas Industry.” Paper at ESREL Conference, 19-22 Sept. 2011.

<sup>9</sup> Pembina Institute. 2011. “Comparing the Arctic Offshore Oil and Gas Drilling Regulatory Regimes of the Canadian Arctic, the U.S., the U.K., Greenland, and Norway.” Review conducted for the Canadian National Energy Board by The Pembina Institute. Available at [www.pembina.org/pub/2227](http://www.pembina.org/pub/2227).

<sup>10</sup> Ibid.



**Figure 1: Arctic Offshore Drilling Regulatory Approaches by Nation**

Throughout this document, an effort is made to identify instances in which the potential Arctic Regulations addressed here are consistent with international regulatory efforts as per the desired goals of Executive Order 13609, and where it seems that new Arctic Regulations may diverge from international approaches that allow for performance-based regulation.

## 1.4 Benefit Cost Analysis (BCA) Parameters

BCA is the accepted methodology for capturing and understanding the tradeoffs between regulatory options. Every BCA is based on certain key assumptions. The parameters of the BCA conducted for this report are set forth below.

### 1.4.1 Defining a Baseline

The baseline sets the parameters of a BCA by providing the starting point for measuring benefits and costs. Depending on how the baseline is defined, the costs (and benefits) of a proposed regulation may vary considerably. The OMB's guidance to federal agencies conducting BCA as part of an RIA states,

*"The baseline represents the agency's best assessment of what the world would be like absent the action."<sup>11</sup>*

The baseline that is used for this analysis, and the baseline that OMB should use for its own analysis accounts for those costs that are incurred (and benefits that are derived) as a result of existing regulations applicable in the Arctic, and does not include practices or constraints that may have been imposed in the past by agencies on a case by case basis, or may have been agreed to on a case by case basis by operators. This baseline captures the best assessment of what the world looks like for operators in the Arctic, absent new Arctic Regulations.

Other baselines considered for this analysis included the OCS regulations that apply to the Gulf of Mexico (GOM), and existing regulatory obligations that are being applied piece meal in the Arctic under a variety of permits and agreements. It was determined that both of these options would present a skewed analysis.

If the baseline was defined as merely those OCS regulations that apply to the GOM, the analysis would not be addressing the current state of regulation in the Arctic, because there is

<sup>11</sup> Office of Information and Regulatory Affairs, Office of Management and Budget. "Regulatory Impact Analysis: A Primer." Available at ([http://www.whitehouse.gov/sites/default/files/omb/info/ereg/regpol/circular-a-4\\_regulatory-impact-analysis-a-primer.pdf](http://www.whitehouse.gov/sites/default/files/omb/info/ereg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf)) accessed September 23, 2014.

already a regulatory differential between the GOM and the Arctic, despite the application of OCS regulations in both regions. For example, the regulatory application of species protections by the U.S. Fish & Wildlife Service (USFWS) and the National Marine Fisheries Service (NMFS) pursuant to the Marine Mammal Protection Act (MMPA) differs in the Arctic OCS from the Gulf of Mexico. Thus, review or analysis of the regulatory environment in the GOM serves as a point of comparison, but does not provide an accurate baseline for a BCA of the new Arctic Regulations.<sup>12</sup>

A different, but equally problematic approach to the baseline, would be to incorporate into the baseline voluntary operator actions and piecemeal regulatory policy calls. This would severely skew any BCA of the new Arctic Regulations because they are not a part of existing regulations. Were these temporary and shifting burdens included in the BCA baseline, the analysis would present an artificially low magnitude of impact in terms of cost of the new Arctic Regulations.

#### **1.4.2 Time Frame for Analysis**

The duration of the exploration and appraisal period in the U.S. Arctic OCS is estimated to be 20 years for a basin-wide exploration program. Therefore, the time horizon used to estimate these exploration and appraisal-related costs is 20 years and the Present Value (PV) calculations are presented over a 20-year timeframe.

#### **1.4.3 Discount Rate**

The BOEM adopted a real 3 percent discount rate for their 2012-2017 analysis in support of the 2012-2017 lease program.<sup>13</sup> In order to be consistent with the BOEM, the discount rate used in the analysis is a 3 per cent real discount rate.

#### **1.4.4 Anticipated U.S. Arctic OCS Production**

The exact amount of oil that may ultimately be produced from the U.S. Arctic OCS is unknown. A number of estimates have been developed utilizing different methods and assumptions about the technical and economic feasibility of recovering the undiscovered oil. For example, a recent document from the BOEM estimates that economically feasible oil in the Alaska OCS may range from 0.25 billion barrels of oil to 20.52 billion barrels, with an additional 0.15 to 73.35 trillion cubic feet (tcf) of natural gas. Summing the oil and gas produces an estimated 0.28–33.11 billion barrels of oil equivalent (BBOE). An earlier estimate from the BOEM (2006) placed economically recoverable oil resources at between 3.27 and 32.10 BBOE, and in 2008 the U.S. Geological Survey (USGS) placed all Arctic oil and gas resources (whether recoverable or not) at 72.77 BBOE.

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<sup>12</sup> For example, the GOM has been exempt from leasing processes outlined in the Outer Continental Shelf Lands Act Amendments of 1978, See "Deepwater Horizon: The Gulf Oil Disaster and the Future of Offshore Drilling" National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Report to the President, 2011, pp. 59 – 63 for a good discussion of the exemptions for the Gulf of Mexico and how these came about.

<sup>13</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012. "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017." Available at [http://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Leasing/Five\\_Year\\_Program/2012-2017\\_Five\\_Year\\_Program/PFP%2012-17.pdf](http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf) accessed August 29, 2014.

For the purpose of this analysis, we follow the estimates provided in the 2011 report by Northern Economics and University of Alaska, Institute of Social and Economic Research (ISER): production of 6.34 BBOE in the Beaufort Sea and 6.16 BBOE in the Chukchi Sea. This estimate falls in the mid-range of all other estimates reviewed, and is therefore useful for the purpose of this analysis. However, it must be acknowledged that a more accurate assessment of the expected size of the resource will not be known until after the exploration phase has come to completion.

## **1.5 Summary**

This report provides the OMB with information for the regulatory review of the draft Arctic regulations. Three potential rule elements will be analyzed in terms of benefits and costs, use of performance standards where feasible, and the consistency with international regulatory trends. The three potential new rule requirements analyzed are 1) a same season relief rig requirement, 2) seasonal drilling limitations, and 3) a requirement that an operator have 100 percent mechanical recovery capacity.

## 2 Costs and Benefits - Same Season Relief Rig (SSRR)

In 2011, Shell detailed its SSRR capacity in its EP, which the BOEM approved. It is believed that the DOI is considering a requirement in the draft Arctic regulations that all U.S. Arctic OCS oil and gas drilling operators have a second relief rig under contract and available to drill a same season relief well. As set forth below, the costs of a SSRR are substantial and significantly misaligned with the theoretical benefits of this proposed asset.

### 2.1 Background information

In order to accurately assess the costs and benefits of such a SSRR requirement, it is necessary to understand both the risk of a loss of well control, and the conditions under which a second relief rig would be utilized by an operator to stop a loss of well control that has resulted in a release of hydrocarbons to the environment. As a preliminary matter, it should be noted that a loss of well control does not necessarily mean that hydrocarbons have been released into the environment. When a well control incident does occur, it is usually handled quickly and without impact to the environment.

The risk of a well blowout<sup>14</sup> associated with an uncontrolled flow of oil of a significant volume is very low. The BOEM has conducted numerous analyses of these scenarios, referring to them as WCD scenarios, or a very large oil spill (VLOS).<sup>15</sup> The BOEM analysis makes it clear that the probability of this scenario is extremely low, estimated as a 0.00068 chance (less than 68/1000 of one percent, or one in 1,543) per well that a blowout of a volume ranging between 10,000 barrels of oil (bbls) and 149,999 bbls would occur.<sup>16</sup>

The difficulty with reliably developing these analyses stems from the fact that data are incomplete regarding these low probability events in the U.S. Since the DOI began keeping incident records (beginning in 1971), none of the 41,000 wells drilled over more than 40 years has ever depended upon a relief well to be drilled to control the blowout (relief wells have been used to plug and abandon wells). Even during the Macondo Incident, the well was controlled with a capping stack and the relief rig was only used to subsequently plug and abandon the well. As a result, forecasts are developed based on international blowout data that has been gathered across countries with a wide variety of environmental protocols in place. Hence, the statistical probability is very difficult to ascertain.

What is learned from studying the history of blowouts and the history of incidents of lost well control is that these events most often result in small volumes of oil released, and well control is most often regained through the hierarchy of well control strategies. The hierarchy of well control refers to the steps that an operator would take following a loss of well control. In order to

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<sup>14</sup> A blowout is the loss of well control or uncontrolled flow of formation or other fluids, including flow to an exposed formation (an underground blowout) or at the surface (a surface blowout), flow through a diverter, or uncontrolled flow resulting from a failure of surface equipment or procedures.

<sup>15</sup> Appendix B of the Final Supplemental Environmental Impact Statement, Chukchi Sea Planning Area, Oil and Gas Lease Sale 193 In the Chukchi Sea, Alaska, Volume I. Chapters I – VI and Appendices A, B, C, D, August 2011 has a good discussion of the VLOS forecast and planning process.

<sup>16</sup> Ibid. Page B4.



determine the relative benefits of a SSRR, it is important to understand which events would have to occur in order for an operator to require a second rig to respond to a loss of well control.

In fact, there is a list of low probability events that would have to occur before an operator considered drilling a relief well with a second rig. First, the operator would have to experience a “kick” or an indication that its drilling muds are no longer sufficiently controlling well pressure.<sup>17</sup> This is less likely to occur in Alaska as opposed to other environments given the pressure conditions in the Arctic, which differ from most operating theaters (e.g. Gulf of Mexico). Wells in the Arctic are hydrostatic or very mildly geopressured, whereas Deepwater Gulf of Mexico wells are generally overpressured. These conditions make controlling a well with mud easier for the operator. Additionally, an operator’s approach to preparing its drilling mud system is based on extensive seismic information it obtains in advance of drilling, including regional well data with existing pore pressure.

Second, assuming an operator experienced a “kick” the first control strategy is to adjust mud weight. “Kicks” occur when the pressure differential between the well bore and subsurface narrows to the point of imbalance. Arctic operators utilize early kick detection technology and monitor well conditions through real time operating centers staffed with well experts reviewing data relating to pressure and temperature that is collected in real-time from rig sensors. These well experts are able to review to these data quickly and are in a position to provide advice if well parameters merit taking action.

Third, assuming an operator could not control a loss of well control or integrity using mud weight adjustments, the next strategy is to use the BOP to shut in the well and allow pumping operations to regain hydrostatic control. The BOP is fitted with a number of pipe rams and annular preventers to allow closure around various pipe sizes and shapes and retain full rated pressure.

It is only once these significant and statistically extremely low probability events occur that a loss of well control would result in a release of hydrocarbons to the environment. However, even if that occurred, there would be a number of other low probability events that would have to occur before a SSRR would be theoretically utilized. If an operator were not able to stop the flow using the pipe rams or annular preventers,, it would attempt to do so using one or both of the shear rams in the BOP stack(that can cut pipe and close off the wellbore if required). If the actuation of the BOP were the failure mechanism, there is also an independent ROV operated remote actuation panel in place for the BOP stack.

If the BOP activation trigger(s) fails, the lower marine riser package (LMRP) and/or the BOP could be removed or cut away and a new assembly, made possible by a pre-staged or readily transportable capping system, would be lowered into place and connected, creating a leak proof seal to shut in the flow. In the case of Alaska OCS operations, this system would be located aboard support vessels even before drilling begins. This capping system is modeled after the

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<sup>17</sup> Under normal operating circumstances, the downhole fluid pressures in a well are controlled by the hydrostatic pressure provided by drilling mud. If the balance of mud becomes incorrect, formation fluids (oil, gas, and/or water) begin to flow into the wellbore and up the pipe, a phenomenon called a “kick.”

apparatus that eventually stopped the Deepwater Horizon blowout in the Gulf of Mexico in 2010 (“Macondo Incident”).

It is only if the capping stack failed, that an operator would be reliant on a relief well to control the well. This relief well could be drilled using the primary drilling rig equipped with a second BOP. It is only if the primary rig is unavailable to drill the relief well because it was damaged in the blowout, that an operator would use a second rig to drill a relief well.

There may be some misperception that in the Arctic a SSRR is necessary because it is the only mechanism an operator has to perform a final “kill” of a well prior to the onset of winter ice. However, in the event of a low probability high-consequence event that necessitated that a blown out well be plugged and abandoned, there are other mechanisms that currently exist that would allow an operator to kill a well before the onset of winter, even absent a second rig. For example, the operator could use the capping stack to stop the well flow at the seafloor and then return the following season to perform a final kill of the well. Alternatively, the operator’s primary rig could be used to drill the relief well, or a same season static kill could be performed as was done during the Macondo Incident.

## 2.2 Cost

The annual cost of supplying an additional stand-by same season relief rig is \$212 million.<sup>18</sup> This cost includes the cost of providing a separate drill rig to serve as a relief rig for the entire season (\$183 million)<sup>19</sup>, the additional cost of the required tow vehicles (\$23 million) and a support vessel<sup>20</sup> (\$7 million), both of which include a 20 percent additional cost above the global average to account for specialization for arctic operations. Over the 20 year period, the present value of the annual \$212 million cost is \$3.2 billion.

## 2.3 Benefit

The benefits of the SSRR are calculated as the expected additional reduction in risk to the environment in present value over a 20 year period.

The approach used in this report to estimating this environmental benefit (or reduction in risk) follows from the methodology used by the BOEM to develop estimates of environmental costs of the most recent Five Year Lease Program.<sup>21</sup> Their approach was to estimate the environmental cost of likely spills and then use those environmental costs as potential damages avoided (i.e., environmental benefits) through implementation of a regulatory action. The BOEM uses the cost of restoration activities required to mitigate and compensate following oil spills based on Natural Resource Damage Assessment (NRDA) costs from actual oil spills to approximate the value of environmental harm. This approach is called the benefits transfer method and is also used by DOI and National Oceanic and Atmospheric Administration (NOAA). The approach calibrates economic values estimated for an existing (and studied) site and transfers them to a new site, in this case the Arctic. For the Arctic region, the Offshore Environmental Cost Model (OECM)

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<sup>18</sup> Estimates may not sum to \$212 due to rounding.

<sup>19</sup> Fearnley Offshore, 2014, Monthly Rig Report, September 2014, page 7 (Norway 5<sup>th</sup>/6<sup>th</sup> Gen).

<sup>20</sup> RS Platou Offshore Research, 2014, Global Support Vessel Monthly September 2014, page 4.

<sup>21</sup> Ibid.

authors explain that lack of prior data makes the benefits transfer difficult, so they determined that the (spilled) cost of the losses in the Arctic would be double the per barrel (spilled) cost of the losses estimated in the GOM.<sup>22</sup>

Ultimately, the results of the BOEM analysis of potential environmental cost of a catastrophic spill associated with the 2012-2017 lease program and associated production in the Chukchi and Beaufort Seas is a cost of \$0.080 billion for the Chukchi Sea and \$0.020 billion for the Beaufort Sea. In the document, the two theaters are anticipated to produce 1.44 billion bbls and 290 million bbls, for the Chukchi and Beaufort Seas respectively, as this document covers only the portion of total production that is anticipated to result from the 2012 to 2017 lease sales. Simplifying these costs to a per barrel of production estimate and updating to current year dollars produces an estimated \$.056 in environmental cost per barrel produced for the Chukchi Sea and \$.070 for the Beaufort Sea per barrel of produced oil.

Using the total estimates of 6.34 BBOE for the Beaufort Sea, and 6.16 BBOE for the Chukchi Sea produces a total of \$791 million overall environmental costs that could potentially be reduced to create environmental benefits (See Table 1). It should be noted that the economic analysis from the OECM model produces a net loss in environmental benefit overall when comparing the lease program with not producing OCS oil. That is because the model assumes that if oil is not produced domestically, it will be imported from other countries where there would likely be greater environmental damage than would occur if the same barrel of oil were produced in the U.S. where environmental regulation is enforced.

<b>Table 1: Estimated Value of Environmental Cost of Existing Arctic Oil Program</b>					
<b>Theater</b>	<b>BBOE from 2012 – 2017 OCS Lease Program (BBOE)</b>	<b>Environmental Cost from BOEM OCS Lease Program (million \$)</b>	<b>Cost per Barrel</b>	<b>Anticipated BBOE Total</b>	<b>Cost for Total (million \$)</b>
Beaufort Sea	0.290	\$20	\$0.070	6.34	<b>\$443.6</b>
Chukchi Sea	1.440	\$80	\$0.056	6.16	<b>\$347.2</b>
<b>Total Arctic</b>	<b>1.730</b>	<b>\$100</b>	<b>N/A</b>	<b>12.5</b>	<b>\$790.9</b>

The results show that overall there is \$791 million in expected environmental costs of exploration and production. These costs represent the potential environmental benefits of the regulation in terms of avoided damages. In other words, if all damages were avoided, this would produce an estimated expected \$791 million in environmental benefits over 50 years. However, the true benefit potential of the SSRR is somewhat less than this estimated amount because some of the estimated environmental damage that would occur stems from the more frequent but smaller volume of spills that are stopped quickly through the hierarchy of well control methods, and therefore would not be reduced by the presence of the SSRR.

<sup>22</sup> Ibid. pages 67-8. The dollar value of per barrel spill costs in the GOM was estimated at \$642 per barrel spilled, and was therefore doubled to \$1,284 per barrel spilled in 2012 dollars for the Beaufort and Chukchi Seas.

## 2.4 Conclusion

Ultimately, while infinite incremental risk reduction could occur to bring about smaller and smaller benefits through the use of prescriptive requirements, such as a SSRR requirement, this approach is not the best use of societal resources. A better solution would be to provide incentive for technological innovation that could provide the additional risk reduction equivalent to that afforded by relief well drilling capabilities. An example of how such a performance-based approach could be structured can be found in Canada.

In a 2011 report, the Canadian NEB opened the door to the possibility of allowing for something other than “same season relief well capability,” stating that:

“...the intended outcome of the Same Season Relief Well policy is to kill an out of control well in the same season in order to minimize harmful impacts on the environment. We will continue to require that any company applying for an offshore drilling authorization provides us with specific details as to how they will meet this policy. **An applicant wishing to depart from the policy would have to demonstrate how they would meet or exceed the intended outcome of our policy... We are open to changing and evolving technology...**”<sup>23</sup> (emphasis added)

The NEB has recently agreed to hear proposals for alternative approaches from two permit applicants.<sup>24</sup> The NEB’s approach on this issue is a prime example of a regulatory environment that is goal oriented, focusing on performance objectives that can provide economic incentive to continue to improve technology so that equivalent technology can be used to potentially reduce exposure periods and spill volumes.

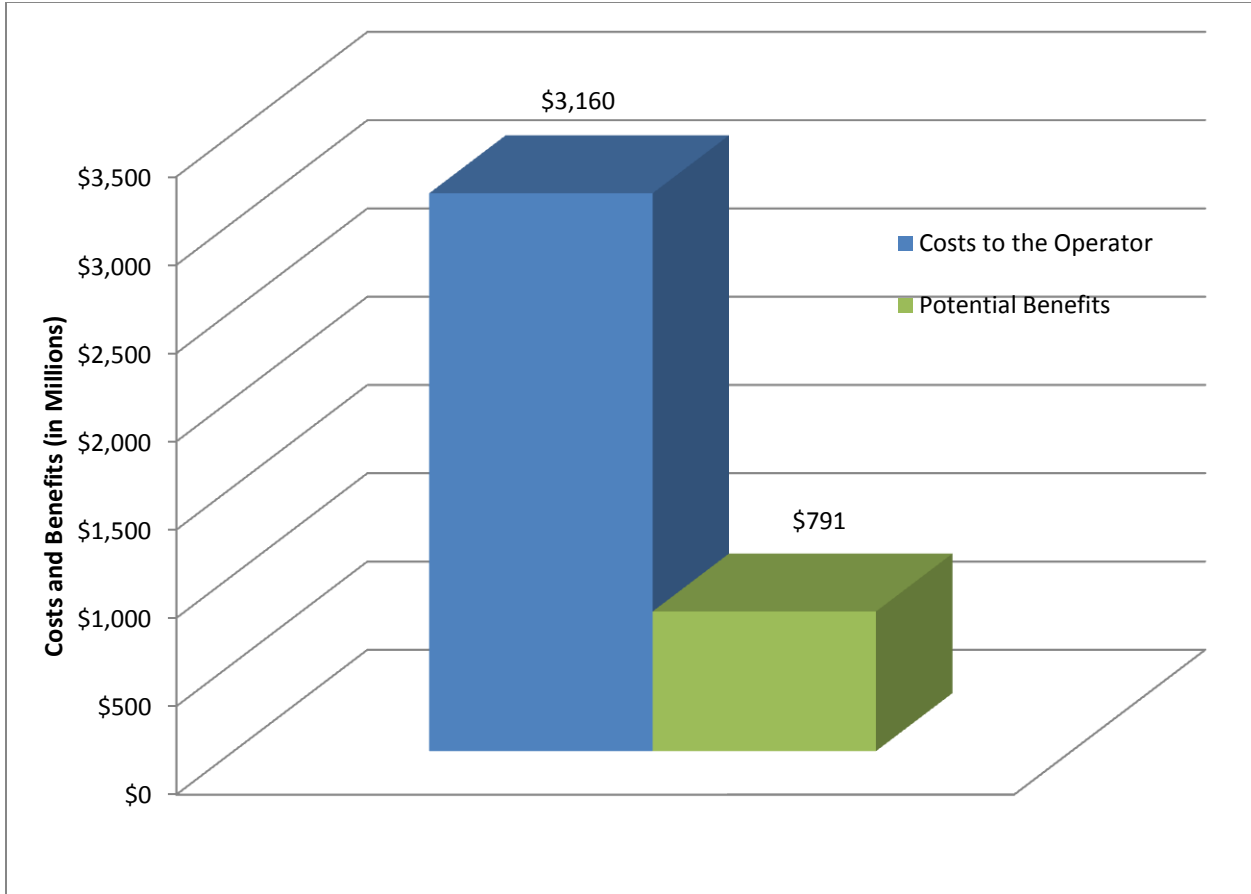
Should the new Arctic Regulations include a prescriptive SSRR requirement without the option for a lessee to prove that they have same season relief well equivalency, then the U.S. may be foregoing an opportunity to promote improved well control technology through a performance standard, and instead would create significant additional costs. Such regulation would also represent a lost opportunity to create cross-border harmonization of policy and to establish international leadership on this issue. The benefits of such a prescriptive requirement are very remote and uncertain, while the costs are quite certain.

Over 20 years, the present value of the cost of maintaining a SSRR is estimated to be \$3.2 billion. The benefit of this potential prescriptive measure is at the very most \$791 million – or about 25 percent of the cost, as illustrated in Figure 2. Operators will not be incentivized to engineer new well control solutions if regulations require that they bring a SSRR to theater, irrespective of what other well control technologies they have available.

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<sup>23</sup> National Energy Board. December 2011. “Review of Offshore Drilling in the Canadian Arctic.” Pg. 40. Available at ([www.neb-one.gc.ca](http://www.neb-one.gc.ca)).

<sup>24</sup> Canadian National Energy Board. July 11, 2014. “NEB to Review Proposals Related to Same Season Relief Well Policy.” Press Release. Available at (<http://www.neb-one.gc.ca/clf-nsi/rthnb/nws/nwsrls/2014/nwsrls24-eng.html>).



**Figure 2: Potential Costs and Benefits of Implementing Same Season Relief Rig Requirement under the Proposed Regulations (Present Value over 20 Years)**

Innovation in the realm of well control is not far in the future, it is taking place now. In the Arctic, and in the wake of the Macondo Incident, several specific technological advancements have strengthened the existing well integrity system including improved well designs, better testing of barriers, and more robust BOP systems. Operators are also currently exploring additional new technologies for Arctic spill control that might result in equivalent or superior protection compared to same season relief well risk reduction. A SSRR requirement stifles innovation, is out of step with other countries and provides a minimum marginal benefit relative to cost of implementation. Allowing SSRR equivalency will incentivize the industry to continue to develop these new technologies.

### 3 Costs and Benefits – Seasonal Drilling Limitations

In its 2011 approval of a Shell EP for drilling in the Chukchi Sea,<sup>25</sup> the DOI imposed a hydrocarbon blackout date beginning September 24<sup>th</sup> of each year, after which time no drilling into hydrocarbons was permitted. The DOI's decision to preclude Shell from drilling into hydrocarbons after September 24<sup>th</sup> in 2012 was predicated on a desire to ensure that Shell could have a SSRR on-site and complete a relief well in advance of November 1<sup>st</sup>. It is believed that the DOI is considering including a similarly prescriptive requirement on the end-of-season for Arctic operators in its draft Arctic regulations. As set forth below, such a prescriptive regulatory requirement cannot be justified from a benefit-cost perspective.

#### 3.1 Cost

In contrast to the Gulf of Mexico, in the Alaska OCS each day of lost drilling is very costly due to the fact that there is on average only 100 days of open-water each season.<sup>26</sup> The economic cost of a lost drilling day involves three elements: (1) the spreading of the extraordinary fixed cost of one season of drilling across fewer drilling days in a given season- increasing the "cost per day" as fewer days are available; (2) the increase in the chance that an additional season of exploration drilling (with full financial and environmental costs considered) will need to be undertaken in order complete appraisal; and (3) the reduction in the expected return on a fixed lease that has already been purchased.

This first cost, the lost fixed cost that is incurred by the lessee, is developed through estimates of the overall cost of a full season, divided by 100 days to create a per day cost, minus the amount of cost that is recoverable (i.e. not fixed). This per day fixed cost is then multiplied by the number of lost days (38 days between September 24<sup>th</sup> and November 1<sup>st</sup>). The second cost, the increased chance that an additional season of drilling is needed to complete the exploration and appraisal phase is not quantified but merely reported for qualitative consideration. The third cost, which is the reduction in the expected return on exploration, is based on the appropriate metric for OMB's regulatory review, and that is the net national benefit to the nation. For this estimate, ENVIRON reviewed prior analyses from the DOI on this topic, and has derived estimates of costs to the nation for one lost day of exploration and appraisal drilling.

To evaluate the cost to the lessee, ENVIRON has reviewed the financial costs of one season of drilling in the Alaska OCS with industry leaders. The costs are estimated at \$1.5 billion per season. Assuming that two drilling rigs are operating (one each in the Chukchi and Beaufort Seas) and utilizing the 100-day drill season this results in a daily cost of \$15 million if the costs were spread evenly across all drilling days. If one day is lost, then all of the fixed cost that would otherwise be spent on the investment in exploration drilling would be lost for that day – with

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<sup>25</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management, Alaska Outer Continental Shelf Region David W. Johnston, Regional Supervisor, Leasing and Plans, letter to Ms. Susan Childs, Shell Gulf of Mexico Inc., December 16, 2011.

<sup>26</sup> This number is a conservative estimate based on seasonal analysis indicating that, on average, there are 100 days of open water for exploration activities available between July 1 and November 1. There are in fact about 123 calendar days between July 1 and November 1, but on average the expected number of days of actual drilling during this period would (on average) be closer to 100 given lost days attributable to a number of factors, including avoidance of subsistence activities and limitations on ice management due to marine mammal protections.

none of the expected return from drilling. This high fixed cost component of drilling is related to the fact that (unlike the GOM) labor and assets that locates in the Arctic cannot immediately go elsewhere to find other work. Due to the proximity to other employment opportunities, workers in the GOM can pursue temporary work elsewhere if a rig shuts down for a few days or weeks. However, these opportunities are not available for workers in the Arctic. Similarly, once the drilling costs are expended for the season, there is little opportunity to recover costs that are spent for underutilized drill days.

After reviewing the total costs for drilling during a full season, ENVIRON worked with industry leaders to determine that at most only 20 percent of the daily costs could be recovered if the drilling season is reduced. This is most likely a high estimate as it would depend on being able to reuse or resale unused materials that were not needed, as well as save on fuel and other operating costs. Using this estimation for foregone daily cost of a season reduction produces a daily loss of \$12 million (80 percent of the daily cost of \$15 million is \$12 million) to the operator. This estimate can be thought of as the sunk cost of the drilling that was not able to occur due to regulation. The cost estimates for drilling season limitations include the hydrocarbon blackouts for both theaters. It is assumed there are 100 drilling days per year over a 20 year exploration and appraisal phase, with 38 days lost per season. This results in a present value cost to the operator of \$6.8 billion.

### 3.2 Costs to the Nation

The most recent “net benefits” analysis of oil and gas development of the Chukchi and Beaufort Seas was performed by the BOEM in support of the program recommendations for its 2012-2017 leasing program.<sup>27</sup> This program includes 15 potential offshore oil and gas lease sales, 12 in the Gulf of Mexico and three in Alaska. The three Alaska lease sales will be held in the Beaufort Sea, the Chukchi Sea, and Cook Inlet, respectively. Compared to older analyses (conducted for the 2002-2007 and 2007-2012 lease programs), the 2012 analysis is based on the most up to date and realistic assumptions of oil and gas prices, data sources, and features improvements to the two simulation models used to estimate the program’s net benefits.<sup>28</sup> The discount rate used is the (real) social discount rate of three percent to the beginning year of the program (2012). While the BOEM analysis considers the net benefits associated with all the program areas considered, the analysis presented in this report only addresses leases specific to the Beaufort and Chukchi Seas program areas in order to identify per barrel benefits to the nation specifically from Arctic exploration.

Using the analysis from the BOEM document, benefits per barrel were developed using 2013 dollars (see Table 2 below). It is important to note that for this lease period, unlike the 2002-2007 and 2007-2012 programs, there is anticipated production of natural gas in the Beaufort and Chukchi Seas planning areas in addition to oil production. Thus, in order to derive per barrel

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<sup>27</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012. "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017." Available at [http://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Leasing/Five\\_Year\\_Program/2012-2017\\_Five\\_Year\\_Program/PFP%2012-17.pdf](http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf) accessed August 29, 2014.

<sup>28</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012(a). "Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017." BOEM OCS Study 2012-022.

estimates, a BBOE figure is used. The BBOE is commonly used by oil and gas companies in their financial statements as a way of combining oil and natural gas reserves and production into a single measure. Based on the mid-price range of \$112 per barrel (in 2013 dollars), the per barrel net economic benefit to the nation (net revenue minus financial/environmental cost) is estimated at \$20.12 for the Beaufort Sea leases and \$27.44 for leases in the Chukchi Sea, with the average of \$23.50 per barrel in both program areas.<sup>29</sup>

As stated earlier, there are a number of studies that estimate the anticipated production in these two areas based on specific assumptions. This analysis employs the estimates developed in the 2011 report by Northern Economics and University of Alaska, ISER<sup>30</sup> of 6.34 BBOE from Beaufort Sea and 6.16 BBOE from Chukchi Sea, about \$297 billion in net benefits to the nation are anticipated for a 50 year period of exploration and production. It is the 50-year long production benefits to the nation that are at risk as exploration lease opportunities are reduced or delayed.

<b>Table 2: Benefits and Costs per Barrel and Total Anticipated Net Benefits</b>						
<b>Program Area/ Scenario</b>	<b>Anticipated Production for Proposed Action (in BBOE)</b>	<b>Net Economic Value/ Barrel</b>	<b>Environmental Costs/ Barrel</b>	<b>Net Social Value/ Barrel</b>	<b>Consumer Surplus Benefits/ Barrel</b>	<b>Benefits/ Barrel</b>
Beaufort Sea	0.29	\$12.88	(\$1.96)	\$14.87	\$5.28	<b>\$20.12</b>
Chukchi Sea	1.44	\$21.89	(\$0.25)	\$22.13	\$5.31	<b>\$27.44</b>
<b>Total Anticipated Net Benefits to the Nation Assuming Production of 6.34 BBOE from Beaufort Sea and 6.16 BBOE from Chukchi Sea</b>				<b>\$297 Billion (Net Present Value over 50 Years)</b>		
<b>Sources:</b>						
Moderate scenario, U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012. "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017." Available at ( <a href="http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf">http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf</a> ) accessed August 29, 2014.						
Northern Economics and University of University of Alaska, Institute of Social and Economic Research (ISER). "Potential National-Level Benefits of Alaska OCS Development. Prepared for Shell Exploration & Production." February 2011. Available at ( <a href="http://www.northerneconomics.com/pdfs/ShellOCS/National%20Effects%20Report%20FINAL.pdf">http://www.northerneconomics.com/pdfs/ShellOCS/National%20Effects%20Report%20FINAL.pdf</a> ) accessed July 8, 2014.						
<b>Notes for Per Barrel Estimates:</b>						
All dollar values represent net present value in billions of 2013 dollars.						
All values are discounted at a real discount rate of 3 percent.						
* The low-price case represents a scenario under which inflation-adjusted prices are \$61 per barrel (\$2013) for oil throughout the life of the program. Prices for the mid-price case are \$112 per barrel (\$2013). Prices for the high-price case are \$162 per barrel (\$2013).						

<sup>29</sup> More detailed information on the calculations used in conjunction with the BOEM data are available on request.

<sup>30</sup> Northern Economics and University of University of Alaska, Institute of Social and Economic Research (ISER). "Potential National-Level Benefits of Alaska OCS Development. Prepared for Shell Exploration & Production." February 2011. Available at (<http://www.northerneconomics.com/pdfs/ShellOCS/National%20Effects%20Report%20FINAL.pdf>) accessed July 8, 2014.



A blackout date results in an extended period of time required for the initial E&A of the leases in the Alaska OCS. This would result in at best a delay of the realization of the \$297 billion benefit to the country, and at worst an overall reduction in the total expected return on the lease program. To estimate the value of the delay, a 38 day blackout in each season of an assumed 20 year industry wide exploration and appraisal campaign would mean an additional 760 days of season required to execute the program, or an additional 12 years at the end of the base 20 years. This would lead to a 12 year delay in the realization of the benefit by the nation, which translates to an NPV reduction of approximately \$89 billion.

### 3.3 Benefit

Given the relationship between the hydrocarbon blackout and the SSRR, the analysis of benefits for these provisions is very similar. The BOEM has previously required a hydrocarbon blackout based on the assumption that a relief well would be required to control and kill a late-season blowout prior to the onset of winter ice. Yet, as discussed in Section 2, drilling a relief well is not the only, or the most efficient method an operator could use to control a late season blow out. However, even where the assumption is made that a relief well were the only, or the preferred response, the benefits gained from imposing a blackout window are minimal.

The estimate for the reduction in risk to the environment is calculated using a method similar to the one used to evaluate the financial cost of foregoing the expected net gain attributable to one day of drilling. The environmental benefit (damages avoided) is estimated by dividing the total estimated environmental costs associated with exploration and production of oil in the Beaufort and Chukchi Seas, by the number of days of activity. This will produce a per-day potential benefit that can be multiplied by the number of days the benefit is anticipated to occur.

The approach to estimating this environmental benefit (or reduction in risk) follows from the methodology used by the BOEM to develop estimates of environmental costs of the most recent program of leases.<sup>31</sup> Their approach was to estimate the environmental cost of likely spills and then use those environmental costs as potential damages avoided (i.e., environmental benefits) through implementation of a regulatory action. The environmental cost is estimated in the OECM based on assessing the potential ecologic damages to different OCS areas within the U.S. depending on the expected forecast of a catastrophic spill event. A Habitat Equivalency Analysis (HEA) was conducted to quantify the ecologic losses from an oil spill. Restoration activities to mitigate and compensate for those losses were established following the natural resource damage assessment protocol. The costs of those restoration activities were then estimated using the benefits transfer method outlined above.

As noted above, BOEM determined in its through its analysis of potential environmental cost for the 2012–2017 lease program in the Chukchi and Beaufort Seas is a cost of \$0.08 billion for the Chukchi Sea, and \$0.02 billion for the Beaufort Sea. In the BOEM analysis the two theaters are anticipated to produce 1.44 billion bbls and 290 million bbls for the Chukchi and Beaufort Seas respectively. Simplifying these costs to a per barrel estimate and updating to current year

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<sup>31</sup> U.S. Department of the Interior. Bureau of Ocean Energy Management. 2012. Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017. BOEM OCS Study 2012-022.

dollars produces an estimated \$0.056 in environmental cost per barrel produced for the Chukchi Sea and \$0.07 for the Beaufort Sea per barrel of produced oil.

Using the earlier estimates of 6.34 BBOE for the Beaufort Sea, and 6.16 BBOE for the Chukchi Sea produces an estimated \$791 million in overall environmental costs that might be reduced to develop environmental benefits (See Table 1). Therefore there are \$791 million in expected environmental costs that could be mitigated and that could (when reduced) become the environmental benefit of the regulation.

Dividing this figure (\$791 million) by the number of days of exploration and production would approximate the amount of environmental harm anticipated for any given day by the BOEM. However, several factors could alter that. First, spill risks and flows assumed for the OECM modeling are developed from a combined list of international spills and domestic spills that date back to 1956.<sup>32</sup> Hence, the probabilities of spills are likely much smaller when current spill prevention and response technologies are considered. At the same time, the risks during the hydrocarbon blackout season are potentially slightly greater in terms of magnitude of impact, which would bring estimates of daily gains from a blackout up slightly. However, due to the degree of uncertainty, it is prudent— if anything—to overestimate the benefits. We therefore assume that this 38 day per season blackout (based on 100 days per season) might result in a benefit of up to 38 percent of the entire environmental cost of the program. This would result in a total value of potential benefit from the hydrocarbon blackout of \$300.5 million.

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<sup>32</sup> Ibid. Page 75. BSEE keeps a database on loss of well control incidents, and SINTEF maintains an international database of all spills.

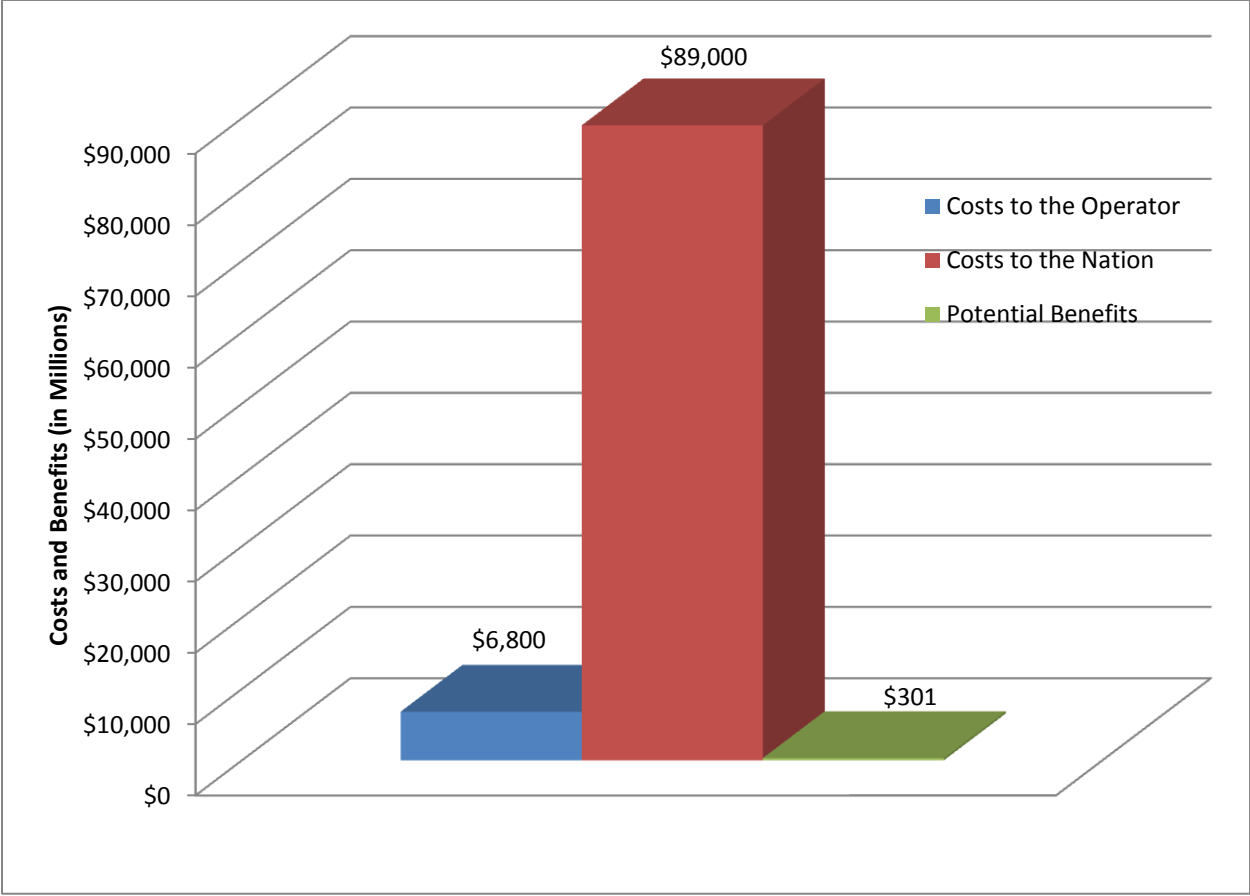
### 3.4 Conclusion

Given that the BOEM already requires that an operator demonstrate that it has a plan to curtail operations in response to emerging hazards,<sup>33</sup> it is not clear that there is any additional benefit to including in regulations a prescribed end of season date. In other areas where BOEM regulates offshore oil and gas activities, including the Gulf of Mexico, the agency does not regulate prescribed end of season dates based on seasonally re-occurring environmental threats, such as hurricanes. Arctic lease stipulations also do not contain any limitations proscribing the duration of an operator's season.

A seasonal limitation that precludes an operator from drilling past September 24<sup>th</sup> cuts into what is considered the "heart" of the Arctic open water season. Given the lack of predictability around the front end of the season (as determined by when ice opens up), the highest value portion of the season for operators begins in mid-September. Further, the benefits of such a limitation are extremely marginal, and could be satisfied or exceeded if the DOI just took the approach that an operator's end of season should be based on a holistic assessment of the assets they plan on bringing to theater. The benefits of this regulatory option are at best \$300.5 million, and at worst uncertain or negative. In contrast, the costs are high both to the lessee and to the nation. The figure below displays our assessment of the benefits and costs of this proposed rule element.

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<sup>33</sup> Operators are required to submit in their Exploration Plans a description of their assets and a Curtailment of Operations Plan (COCP). The COCP sets indicators for a progressive range of ice alert levels and establishes thresholds and protocols for ceasing operations in response to developing hazards.



**Figure 3: Potential Costs and Benefits of Implementing Seasonal Drilling Limitations under the Proposed Regulations (Present Value over 20 Years)**

## 4 Costs and Benefits - 100 % Mechanical Recovery Capacity

The requirement that an operator in the Arctic demonstrate the capacity to respond to 100 percent of its WCD with mechanical recovery is not codified in regulation. However, it is required by the BSEE as a part of its approval of Arctic Oil Spill Response Plans. This is due to the North Slope Subarea Contingency Plan, which is a part of the Alaska Federal/State Preparedness Plan for Response to Oil & Hazardous Substance Discharges/Releases. The North Slope Subarea Contingency Plan provides that depending on the outcome of a NEBA, an operator may be required to bring enough mechanical recovery assets to the theater to respond to 100 percent of its WCD.

It is believed that the DOI may consider addressing oil spill response in its draft Arctic regulations. For this reason, ENVIRON has conducted a BCA of the requirement that an Arctic offshore operator have the capacity to respond to 100 percent of its WCD with mechanical recovery assets. The issue here is not whether an operator actually has to respond to its WCD using exclusively mechanical recovery assets, but whether an operator has to bring sufficient assets to theater to launch a strictly mechanical response when other oil spill response tools may be better suited to the conditions.

As set forth below, this requirement is not justifiable from a cost-benefit perspective. This approach curtails the ability of an operator to develop an environmentally preferred response plan, and requires the operator to maintain a large Oil Spill Response (OSR) fleet in theater, even if other OSR tools are deemed to be more effective in waging a response.

### 4.1 Background Information

As a preliminary matter, it should be noted that the BCA of this potential requirement is premised on the assumption that the requirement would only be applied in an *open-water exploration and appraisal scenario*. In a year round production scenario, a requirement that an operator have the capacity for 100 percent mechanical recovery could only be met if the operator retained an excessive number of icebreakers. If an Estimated Recovery System Potential (ESRP) calculation were applied, the number of icebreakers required for a production scenario could exceed 50. This distinction is critical; while requiring an operator to have 100 percent mechanical recovery capacity in an open-water exploration may be inefficient, requiring that capacity during a year-round production scenario would be cost-prohibitive and preclude development.

The history and precedent for performance-based regulation and the use of NEBA/NEEBA approaches to assess regulatory options (often referred to as a “strategic” NEBA) and to assess specific response options in a specific spill situation (commonly referred to as a “tactical” NEBA) is well established.

Mechanical recovery operations require significantly more personnel, equipment, and corresponding logistics support over a longer period of time than any other response techniques, including the use of dispersants and in-situ burning. Dispersants, which are recognized by the Arctic Response Technology Joint Industry Program (JIP) as a critical response tool for larger spills far from shore in ice-affected waters, can be applied from aircraft

and are efficient on a wide range of slicks.<sup>34</sup> Because aircraft can reach a spill site faster than a vessel (required for a mechanical response), response times are reduced, resulting in faster and better environmental protection.<sup>35</sup> Also, according to a JIP report from October 2013 analyzing dispersant use world-wide,<sup>36</sup> Germany, Greenland, Iceland, Norway, Kazakhstan, and Russia all allow for the potential use of dispersants based on the outcomes of a NEBA process. Within the United States, the concept of using dispersants is currently accepted by the U.S. Coast Guard and in some cases pre-approved based on the outcome of a NEBA process. However, Alaska OCS does not have preauthorization for either in-situ burning or dispersants.

Research has proven that in-situ burning is a safe and proven response technique for Arctic conditions. The in-situ method can rapidly eliminate large volumes of spilled oil and requires less equipment and personnel than other response options, decreasing the impact of the oil spill response effort.<sup>37</sup>

The United States and other countries have realized that oil spill response depends on local conditions, including weather, time of year, type, and amount of oil released and potential habitats affected determine which combination of response options may be most effective. Regulations that require 100 percent mechanical recovery capabilities while failing to give credit for other more effective response options (such as in-situ burning or dispersants) may, depending on the nature of the spill, result in more potential environmental damage and higher safety risks to responders as the optimal combination of response options is not incentivized.

Prescriptive regulations with a predominant focus on mechanical spill response techniques introduce a distortion in risk management response by reducing the incentive for operators in the Arctic to develop new dispersant and in-situ burning technologies relative to the incentive to innovate with respect to mechanical recovery. A regulation that invokes prescriptive technology incentivizes the use of that technology (e.g. mechanical) over others thereby hindering innovation and new advances in technology as the incentives to further develop and explore other technologies is diminished. Oil spill response can best be managed through the careful consideration of all response options, or all the tools in the tool kit and help encourage innovation for future technologies.

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<sup>34</sup> SEA Consulting Group. October 2013. "Dispersant Use In Ice-Affected Waters: Status Of Regulations And Outreach Opportunities - Final Report 2.8." Available at (<http://www.arcticresponsetechnology.org/project-updates/dispersant-testing-under-realistic-conditions/report-on-dispersant-use-in-ice-affected-waters-status-of-regulations-and-outreach-opportunities-task-8-state-of-knowledge-review>).

<sup>35</sup> API Energy. Fact Sheet No. 5. "Dispersant use approvals in the United States. Oil Spill Prevention." Available at ([www.spillprevention.org](http://www.spillprevention.org)) accessed July 31, 2014.

<sup>36</sup> SEA Consulting Group. October 2013. "Dispersant Use In Ice-Affected Waters: Status Of Regulations And Outreach Opportunities - Final Report 2.8." Available at (<http://www.arcticresponsetechnology.org/project-updates/dispersant-testing-under-realistic-conditions/report-on-dispersant-use-in-ice-affected-waters-status-of-regulations-and-outreach-opportunities-task-8-state-of-knowledge-review>).

<sup>37</sup> API Energy. Fact Sheet No. 5. "Dispersant use approvals in the United States. Oil Spill Prevention." Available at ([www.spillprevention.org](http://www.spillprevention.org)) accessed July 31, 2014.

## 4.2 Cost

Failure to allow for OSR credit for in situ burning, natural dispersion, or dispersants shifts costs to mechanical recovery at the expense of effective (and lower cost) alternatives that are available to operators in other locations (e.g. Gulf of Mexico). The annual cost of offshore and near shore OSR vessels and a tanker is \$32.8 million based on estimates from several sources for costs including WorkBoat.com, Marcon International Inc.,<sup>38</sup> and Teekay Tankers Ltd.<sup>39</sup>

The two parts that sum together for the annual cost estimate for the 100 percent mechanical recovery rule element are:

1. No credit for Dispersant – for this element the base annual cost (\$32.8 million) is multiplied by .15 (five percent credit for natural dispersion and ten percent credit for dispersant application) and equals \$5 million;
2. No credit for Burn - for this element the base annual cost (\$32.8 million) is multiplied by 0.1 (ten percent credit for in situ burning) and equals \$3 million; and

Summed together, these two parts equal \$8 million for the annual cost of the rule element. With the annual cost of \$8 million, the cost of this regulation to the lessee totals \$119 million in PV over the 20-year time horizon.

## 4.3 Benefit

As previously stated, other OCS regions of the U.S. and most countries in the world rely on a NEBA to plan for oil spill response. NEBA provides, by definition, the greatest environmental net benefit for that particular situation and circumstances. In contrast, there is a question as to whether or not there is any environmental benefit to be associated with a requirement that 100 percent of the WCD mechanical assets are maintained in the Arctic theater. In 2012, Shell estimated that many of the 20 vessels that were staged in the theater were for oil spill response.<sup>40</sup> It is estimated that vessel requirements would rise in future exploration seasons. This also means the environmental impacts associated with these vessels could increase as well, as normal activities related to more vessels, people and other equipment increases.

The DOI completed a comparative analysis of the environmental sensitivity and marine productivity associated with oil and gas development for the OCS planning areas as part of a revised plan for the oil and gas leasing program<sup>41</sup> and used in the Revised Offshore

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<sup>38</sup> Marcon International, INC, 2013, "Tank Barge Market Report – May 2013" available at: [http://www.marcon.com/library/market\\_reports/2013/tb05-13.pdf](http://www.marcon.com/library/market_reports/2013/tb05-13.pdf), May.

<sup>39</sup> Teekay Tankers LTD. 2014 "Aframax Tanker Spot Rates – Sept 2014" available at: [http://www.teekaytankers.com/files/Tanker%20Rates/2014/Current\\_Tanker\\_RatesSept19.pdf](http://www.teekaytankers.com/files/Tanker%20Rates/2014/Current_Tanker_RatesSept19.pdf), downloaded 19 September.

<sup>40</sup> Slaiby P.E. 2013. Letter from Peter Slaiby, Vice President, Shell Alaska to Doug Morris, Chief of Offshore Regulatory Programs, Bureau of Safety & Environmental Enforcement. 5pp.

<sup>41</sup> U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012. "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017." Available at [http://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Leasing/Five\\_Year\\_Program/2012-2017\\_Five\\_Year\\_Program/PFP%2012-17.pdf](http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf) accessed August 29, 2014.

Environmental Cost Model.<sup>42</sup> Table 3 is summary of the sensitivity for the six OCS program areas by the four major categories analyzed (marine habitats, coastal environments, marine fauna and marine productivity). A separate analysis was completed for climate change sensitivity and used to adjust the overall sensitivity scores, which is not included in this summary. The Arctic OCS program areas are consistently less sensitive than other areas and in some cases, an order of magnitude less sensitive (see marine fauna and marine productivity). This suggests the requirement for 100 percent mechanical recovery in the Arctic cannot be reasonably predicated on the relative sensitivity of the Arctic environment versus that of the Gulf of Mexico.

<b>Table 3: Summary of Relative Environmental Sensitivity to Impact of the OCS Program Areas with Environmental Sensitivity Scores Without the Climate Change Adjustment</b>				
<b>Relative Sensitivity Categories</b>				
	<b>Coastal Habitats</b>	<b>Marine Habitats</b>	<b>Marine Fauna</b>	<b>Marine Productivity</b>
<b>OCS Program Areas and Relative Sensitivity Score</b>	Eastern GOM 9.1	Eastern GOM 43	Central GOM 2.18	Cook Inlet 4.506
	Central GOM 8.9	Central GOM 32	Eastern GOM 1.84	Eastern GOM 1.919
	Western GOM 7.6	Western GOM 32	Western GOM 1.29	Central GOM 1.659
	Beaufort Sea 7.4	Beaufort Sea 32	Cook Inlet 0.47	Western GOM 1.096
	Cook Inlet 5.9	Chukchi Sea 23	Chukchi Sea 0.46	Chukchi Sea 0.132
	Chukchi Sea 4.9	Cook Inlet 17	Beaufort Sea 0.06	Beaufort Sea 0.071

U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM). June 2012. "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017." Available at [http://www.boem.gov/uploadedFiles/BOEM/Oil\\_and\\_Gas\\_Energy\\_Program/Leasing/Five\\_Year\\_Program/2012-2017\\_Five\\_Year\\_Program/PFP%2012-17.pdf](http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/Five_Year_Program/2012-2017_Five_Year_Program/PFP%2012-17.pdf) accessed August 29, 2014.

The following sections present evidence that the potential environmental benefits from adopting a NEBA approach exceeds those gained from a 100 percent mechanical recovery approach and that even the concept of “100 percent mechanical” may be evolving as a result of changes in technology and science.

### 4.3.1 Dispersants

There are naturally occurring microbes in any environment that can feed on and break down crude oil. Dispersants aid this process of degradation by bonding with oil to form tiny droplets (<100 microns), which makes the oil more available for microbial degradation. Wind, current,

<sup>42</sup> Industrial Economics, Inc.; Applied Science Associates, Inc.; Northern Economics; and Dr. Nicholas Z. Muller. 2012. “Forecasting Environmental and Social Externalities Associated with OCS Oil and Gas Development: The Revised Offshore Environmental Cost Model (OECM).” U.S. Department of the Interior, Bureau of Ocean Energy Management. OCS Study BOEM 2012-025.



wave action, or other forms of turbulence help both this process and the rapid dilution of the dispersed oil. The increased surface area of these tiny oil droplets in relation to their volume makes the oil much easier for the petroleum-degrading microorganisms to consume.

Over the past two decades, tests and field experiments have proven that oil can be chemically dispersed successfully in cold ice covered waters.<sup>43</sup> Laboratory studies conducted at Point Barrow, Alaska have shown that indigenous Arctic microorganisms can effectively degrade both fresh and weathered oil. Most importantly, from an environmental protection perspective, Arctic species and their counterparts in southern waters have exhibited similar tolerances to dispersed oil, and the use of dispersant was not observed to increase the toxicity of the oil.<sup>44</sup> Additionally, research has shown that dispersants are effective on unemulsified oil at freezing temperatures.<sup>45</sup> New dispersant gel formulations promise increased effectiveness on cold viscous oils with longer windows of opportunity.<sup>46</sup>

### 4.3.2 In Situ Burning

ISB in ice and Arctic environments is a safe, environmentally acceptable and fully proven technique with numerous successful Arctic field validations over the past 40 years.<sup>47</sup> ISB is suited for use in the Arctic where oil remains fresh and unemulsified for a longer period of time. In 1993, a U.S.-Canada experiment off Newfoundland successfully burned crude oil in fire-resistant booms in the open ocean and monitored a large suite of environmental parameters, including smoke composition (carcinogens, polycyclic aromatic hydrocarbons etc.), residue

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<sup>43</sup> Nedwed, T., W. Spring, R. Belore, and D. Blanchet. 2007. "Basin- scale testing of ASD icebreaker enhanced chemical dispersion of oil spills." Proceedings Arctic and Marine Oilspill Program (AMOP) Technical Seminar. No. 30, Vol. 1, pp. 151-160. Environment Canada, Ottawa, Canada; Mullin, J., R. Belore, and K. Trudel. 2008. "Cold water dispersant effectiveness experiments conducted at OHMSETT with Alaskan crude oils using Corexit 9500 and 9527 dispersants." In: Proceedings of the 2008 International Oil Spill Conference, 4-8 May 2008, Savannah, Georgia. American Petroleum Institute, Washington DC. pp. 817-822; Owens, E.H., and D.F. Dickins. 2014. "Guide to Oil Spill Response in Snow and Ice Conditions." In preparation by Owens Coastal Consultants and DF

Dickins Associates for the Arctic Council EPPR Working Group and International Maritime Organization, London.

<sup>44</sup> Gardiner WW, JQ Word, JD Word, RA Perkins, K McFarlin, BW Hester, LS Word, and CM Ray, 2013. "The acute toxicity of chemically and physically dispersed crude oil to key Arctic species under Arctic conditions during the open water season." *Environ Toxicol Chem* 32:2284-2300.

<sup>45</sup> Venosa, A.D. and E.L. Holder. 2013. "Determining the dispersibility of South Louisiana crude oil by eight oil dispersant products listed on the NCP Product Schedule." *Marine Pollution Bulletin* 66: 73-77.

<sup>46</sup> Nedwed, T., W. Spring, R. Belore, and D. Blanchet. 2007. "Basin- scale testing of ASD icebreaker enhanced chemical dispersion of oil spills." Proceedings Arctic and Marine Oilspill Program (AMOP) Technical Seminar. No. 30, Vol. 1, pp. 151-160. Environment Canada, Ottawa, Canada.

<sup>47</sup> McMinn, T.J. 1972. "Crude Oil Behavior on Arctic Winter Ice: Final Report." Office of Research and Development, United States Coast Guard, Project 734108, Wash. D.C., NTIS Publication No. AP-754, 261 p. (also published as McMinn, LTJG T.J. 1973. Oil Spill Behavior in a Winter Arctic Environment. Offshore Technology Conference, Houston); Norcor. 1975. "The Interaction of Crude Oil with Arctic Sea Ice." Beaufort Sea Project Technical Report No. 27, Canadian Department of Environment, Victoria, BC, Canada; Dickins, D.F., Buist, I.A. 1981. "Oil and Gas Under Sea Ice Study: Vols. 1&2." Prepared by Dome Petroleum Ltd. for COOSRA, Report CV-1, Calgary, AB, Canada (also published in Proceedings 1981 International Oil Spill Conference, Atlanta GA); Buist, I., Dickins, D. 1987. "Experimental Spills of Crude Oil in Pack Ice." Proceedings 1987 International Oil Spill Conference. American Petroleum Institute. Washington, pp 373-381; Allen, A.A. 1990. "Contained Controlled Burning of Spilled Oil During the Exxon Valdez Oil Spill." Proceedings of the Arctic and Marine Oilspill Program Technical Seminar No. 13, Environment Canada, Ottawa. pp. 305-313; Dickins, D., Brandvik, P.J., Bradford, J., Faksness, L.-G., Liberty, L., Daniloff, R. 2008. "Svalbard 2006 Experimental Oil Spill Under Ice: Remote Sensing, Oil Weathering Under Arctic Conditions and Assessment of Oil Removal by In-situ Burning." Proceedings 2008 International Oil Spill Conference, Savannah, Georgia.

toxicity, and upper water column impacts.<sup>48</sup> Results demonstrated that when conducted in accord with established guidelines, ISB is safe and poses no unacceptable risk to human populations, wildlife, or responders.

Numerous agencies, primarily in the United States, have established guidelines for the safe implementation of ISB as a countermeasure. The State of Alaska has incorporated ISB guidelines into its Unified Response Plans since 1994, making it, and the United States, the first Arctic area to formally consider ISB as an oil spill countermeasure.

Most recently, the massive ISB operation in response to the Macondo blowout provided a unique set of full-scale operational data applicable to response planning for Arctic offshore areas in the summer. Approximately 400 controlled burns removed an estimated 220,000 to 310,000 barrels of oil from the Gulf of Mexico. This was the first large-scale application of burning in an operational setting.<sup>49</sup>

The JIP recently published a comprehensive state of knowledge review of ISB in the Arctic, including all known references.<sup>50</sup> Additionally, a new ISB project planned under the Arctic Response Technology JIP includes the validation and testing aerial application systems for chemical herders (agents that force oil molecules to thicken and contract, in much the same way that a drop of soap forces grease in a dishpan towards the edges) using both manned and remote-controlled helicopters. The JIP is also initiating a new project (2014/15) to evaluate the potential of chemical herders under different oil properties and weathering, as well as investigating windows of opportunity for their use.

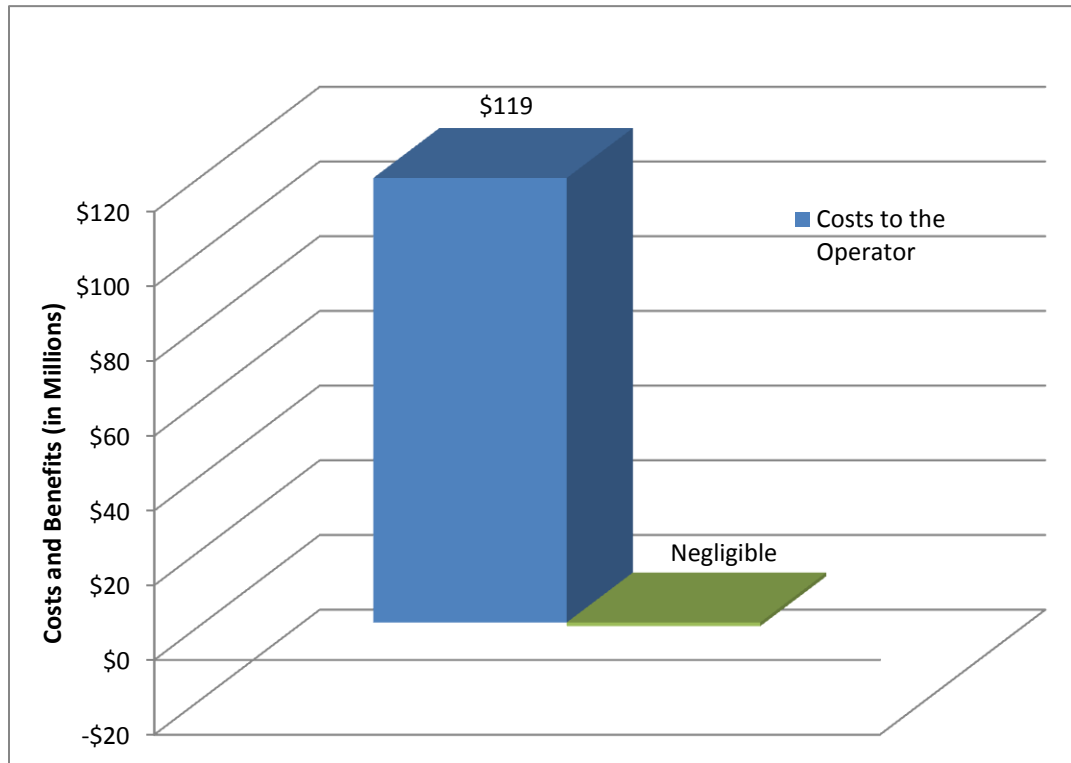
The proposed rule should allow operators to apply the NEBA process to establish an OSRP that is suitable for the prevailing environmental conditions, rather than requiring across the board that all Arctic operators demonstrate capacity to respond to 100 percent of their WCD with mechanical recovery assets. The NEBA process by definition results in the least harm to the environment. Any constraints on potential response options will result in lower benefits. Figure 4 below demonstrates the relationship between benefits and costs.

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<sup>48</sup> Fingas, M. F., D. A. Kyle, N. D. Laroche, B. G. Fieldhouse, G. Sergy, and R. G. Stoodley. 1995. "The Effectiveness of Spill Treating Agents." *The Use of Chemicals in Oil Spill Response*, ASTM STP1252, P. Lane, ed. ASTM, Philadelphia, Pennsylvania.

<sup>49</sup> Allen A.A., D. Jager, N.J. Mabile, and D. Costanzo. 2011. "The Use of Controlled Burning during the Gulf of Mexico Deepwater Horizon MC-252 Oil Spill Response." *International Oil Spill Conference Proceedings: March 2011*, Vol. 2011, No. 1, pp. abs194.

<sup>50</sup> Buist, I.A., S.G. Potter, B.K. Trudel, S.R. Shelnutt, A.H. Walker, D.K. Scholz, P.J. Brandvik, J. Fritt-Rasmussen, A.A. Allen, and P. Smith. 24 October 2013. "In Situ Burning in Ice-Affected Waters: State of Knowledge Report-Final Report 7.1.1 to the Arctic Response Technology Joint Industry Programme."



**Figure 4: Potential Costs and Benefits of Implementing 100 Percent Mechanical Recovery under the Proposed Regulations Present Value over 20 Years**

#### 4.4 Conclusion

Codification of a requirement that an operator bring sufficient assets to theater to launch a 100 percent mechanical response to its WCD would be a move away from international consistency and from the performance based regulatory approach. Such a requirement would not be cost effective, as the cost of this requirement is estimated at over \$119 million, with no measurable environmental or social benefit. In fact, this approach may have the perverse effect of generating a “negative” environmental benefit as adherence to the condition would redirect resources toward mechanical technological innovation and therefore away from alternative spill response approaches that could provide more environmentally beneficial results.

## 5 Conclusion

This report has provided information relative to the regulatory review process underway for proposed Arctic Regulations. Three potential rule elements were evaluated for consistency with U.S. regulatory policy (as set forth in Executive Orders 13563, 12866 and OMB guidance documents), including an analysis of the benefits and costs associated with each element and an evaluation of the degree to which they are in line with presidential directive relating to performance-based regulation. In addition, the three elements were benchmarked for regulatory harmony against existing international standards, protocols, and best practices.

### 5.1 Analysis of the Benefits and Costs Derived from Proposed Elements of a Regulation

Following the protocols for benefit-cost analysis, as set forth in the Executive Orders and OMB guidance referenced above, the table below summarizes the present value of the benefits associated with the proposed elements as well as the present value of the costs of implementation. All three elements have significant costs to potential Arctic operators: \$3.16 billion for same season relief rig capability; \$6.8 billion from seasonal limitations; and \$119 million from a requirement for 100% mechanical recovery capacity. The present value of the benefits associated with the elements are small ranging from negligible in the case of mechanical recovery capacity to less than \$800 million for same season relief rig capability. The net benefits are calculated by subtracting the present value costs from present value benefits. As shown in Table 4, when presented in “net present value” terms (benefits minus costs) this conclusion is even more profound. All three of the proposed rule elements have a negative net present value. Using conservative estimates of benefits (i.e. estimates that err on the side of being greater) the total NPV of the three elements over 20 years is a **loss of \$91 billion to the nation**, including a total loss of nearly \$10 billion to operators.

<b>Table 4: Estimated Costs and Benefits and Net Benefits of Three Key Elements of the Proposed Regulations (Present Value over 20 Years; in Millions of \$2013)</b>			
<b>Potential Costs and Benefits</b>	<b>Same Season Relief Rig</b>	<b>Seasonal Drilling Limitations - Hydrocarbon Blackout</b>	<b>100 Percent Mechanical Recovery</b>
Costs to the Lessee	\$3,160	\$6,800	\$119
Costs to the Nation	None	\$89,000	None
Benefits	\$791	\$301	Negligible
<b>Net Benefits</b>	<b>-\$2,369</b>	<b>-\$88,699</b>	<b>-\$119</b>

For the purposes of OMB’s statutory charge as set forth in EO 12866 that the agency,

*“shall assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, **propose or adopt a regulation**”*

***only upon a reasoned determination that the benefits of the intended regulation justify its costs.***<sup>51</sup>

None of the three proposed elements as they have been defined and evaluated in this report provide benefits that exceed the cost.

## **5.2 Analysis of Elements of a Proposed Regulation against Performance Based Approaches and International Standards**

The proposed rule elements are not performance based, even where obvious performance based approaches are available and would achieve the desired objectives. This analysis has demonstrated that allowing for SSRR equivalency, performance based season limitations, and strengthening the dependence on the NEBA approach may be less costly, and more effective regulatory approaches that respond to the call for performance based regulatory approaches found in Executive Order 12866.

The conclusion of the review is that the costs of the potential elements reviewed in this report significantly exceed their benefits. In addition, if codified in a regulation, these elements would be inconsistent with U.S. policy guidance directing agencies toward performance based regulations and would not be in harmony with international standards and best practices.

On this basis, the recommendation of this report is that OMB reject any proposed regulatory language related to a SSRR requirement (without an equivalency option), fixed seasonal limitations and a requirement for 100% mechanical recovery capacity for spill response plans.

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<sup>51</sup> Exec. Order No. 12866 Section 1(b)(6), emphasis added.

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