United States Department of the Interior
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
WASHINGTON, DC 20240-0001

AUG 1 4 2013

Dr. Walter D. Cruickshank
Chairman
Ocean Energy Safety Advisory Committee
Bureau of Ocean Energy Management
1849 C Street, N.W.
Washington, D.C. 20240

Dear Chairman Cruickshank:

Thank you for submitting the Ocean Energy Safety Advisory Committee (OESC) recommendations to the Department of the Interior (DOI) and the Bureau of Safety and Environmental Enforcement (BSEE) on January 25, 2013. I appreciate the hard work put forth by the entire Committee and the six OESC subcommittees in formulating the 20 recommendations for BSEE's consideration and action.

Over the past five months, BSEE has implemented initiatives that comprise the large majority of the Committee's recommendations. In the text that follows, I will walk you through some of our key accomplishments that address your recommendations. For example, we released the Safety and Environmental Management Systems (SEMS) II final rule, announced a new Safety Institute, conducted two unannounced capping stack deployment exercises, and are currently developing a regulatory framework for drilling offshore in Alaska. The following text addresses your recommendations topically rather than in the order listed in your letter. Our highest priority items are addressed first. Thank you once again for your time and commitment. I hope this letter reflects the level of effort and consideration we have put into responding to these recommendations.

Safety and Environmental Management Systems (SEMS)

On April 4, 2013, BSEE released the SEMS II final rule to strengthen the October 2010 SEMS rule. The rule provides increased protection by supplementing operators' SEMS programs with greater employee participation, empowering field level personnel with safety management decisions, and strengthening oversight by requiring audits to be conducted by accredited third-parties. Implementing SEMS II is part of BSEE's ongoing effort to ensure that the offshore industry makes safety their number one priority. To strengthen this message, BSEE released a Safety Culture Policy Statement to inform the offshore community of BSEE's safety expectations. Finally, I have reached out to offshore operators to encourage improved SEMS audits, and I continue to work with all SEMS stakeholders to ensure a continually improving process. Enclosures 1-3 provide more information about both SEMS II and the Safety Culture Policy Statement.

The DOI working with the USCG and other appropriate agencies should request and work with industry to amend the current version of American Petroleum Institute (API) Recommended Practice (RP) 75 to incorporate all operations and activities that take place on an operator's facility in addition to the ones only covered by BSEE's jurisdiction.

BSEE has a very active Standards Team that coordinates our participation in standards organizations such as the American Petroleum Institute (API), National Association of Corresion Engineers, American National Standards Institute, and American Society of Mechanical Engineer. BSEE representatives are actively participating in the API RP75 revision process.

Additionally, BSEE continues to explore policy and regulatory options with other agencies such as the Occupational Health and Safety Administration (OSHA) and the U.S. Coast Guard (USCG). The Bureau contributes its expertise to an interagency initiative lead by OSHA that is aimed at harmonizing performance-based regulatory regimes and safety management requirements for all domestic energy operations (onshore, offshore, upstream, downstream, and transportation). BSEE is working with the USCG through the joint BSEE/USCG Prevention Work Group and recently issued a new Memorandum of Agreement (MOA-OCS-07, Enclosure 4). BSEE and the USCG will use this agreement to establish a process for the identification of offshore safety and environmental management requirements within the jurisdiction of both agencies and to spur the development of joint policies and guidance. The agreement also provides a mechanism to ensure that all future regulations, policies and guidance are enforced consistently by both agencies.

BSEE uses memoranda of understanding (MOUs) and MOAs with other agencies to coordinate regulatory activities for specific types of equipment and processes, but these interagency agreements do not limit the scope of the SEMS program that must be maintained by the operator under these regulations. An operator's SEMS program should address all oil and gas activities and should not be limited to the components listed in the interagency agreements. BSEE has removed the phrase ''activities that are regulated under BSEE jurisdiction'' from the final SEMS II rule to clarify that all these activities must be addressed.

BSEE should amend the Safety and Environmental Management System (SEMS) regulations such that "major contractors," in addition to the Operator, are responsible for having a SEMS program that holistically covers operations and activities that take place on the OCS. Bridging documents should also be required between Operators and "major contractors" in order to adequately detail the linkage of the SEMS programs and specific roles and responsibilities. The term "major contractor" means drilling contractors and production facility owners or facility operators when not considered to be the Operator.

BSEE is evaluating the possibility of requiring contractors to have a SEMS program while performing operations on the OCS. Currently, regulations at 30 CFR § 250.1914 state that both the operator and the contractor must document their agreement on appropriate contractor safety and environmental policies and practices before the contractor begins work at the operator's facilities. Operators must ensure that contractors have their own written safe work practices. Contractors may adopt appropriate sections of the operator's SEMS program. These agreements are commonly referred to as "bridging documents." BSEE is participating in the industry efforts to issue API Technical Bulletin 97, Well Construction Interface Document Guidelines that will strengthen the interface between the drilling contractor's safe work practices and existing well plan documents. The Bulletin also focuses on the alignment of the operator's and drilling contractor's management of change processes and well plan risk assessments.

All personnel, including contractors, must be trained in accordance with the requirements of 30 CFR § 250.1915. Operators must verify that contractors are trained in accordance with this regulation prior to performing a job. Moreover, BSEE is increasingly holding contractors accountable and expects that all offshore contractors will have comprehensive safety programs in place. The Bureau also released an interim policy document (IPD) stating that inspectors will issue Incidents of Noncompliance to contractors that are not in compliance with the regulations (Enclosure 5).

Currently, API RP 75 encourages drilling contractors with significant operations to consider developing a complete SEMS for offshore operations and facilities. The Bureau is working with the USCG on an Advanced Notice of Proposed Rulemaking that would require safety management systems for offshore service vessels on the OCS.

BSEE is currently in the middle of the first SEMS audit cycle and will use feedback from the audits to help identify any gaps in facility/activity coverage.

BSEE should work with industry to develop an assessment methodology and/or audit protocol that tests the process safety focus of a SEMS program. This would include evaluating the appropriate performance measures and controls as part of a comprehensive improvement process to SEMS. This assessment methodology could be developed in conjunction with the Center for Offshore Safety and should be supported by appropriate leading indicators that should be regularly reported.

BSEE recently released the SEMS II regulation that requires independent audit service providers (ASPs) to audit operators' SEMS programs. ASPs must be accredited by a BSEE- approved accrediting board (AB). ASPs must meet Center for Offshore Safety (COS) requirements for qualification and competence of audit teams and audit performing third parties into its regulations. These standards provide training requirements for auditors, and require that they understand process safety.

BSEE serves on multiple COS subcommittees and regularly advocates for development of an audit methodology that provides continuous feedback to improve the process safety protocols and performance of offshore operators and contractors. We will continue to work with COS to establish audit protocols that not only serve as guidelines for industry, but will also provide BSEE with trend data to aid in promotion of continuous improvement in the development of an effective SEMS program.

BSEE is in the process of reviewing operators' SEMS program audits and anticipates using this information to further strengthen the offshore oil and gas SEMS initiative. BSEE also released a

SEMS IPD that will encourage companies to review their SEMS plan with measures when an inspector notes a safety or process safety issue (Enclosure 6).

Finally, a significant effort has been initiated by BSEE to develop a near-miss reporting program and a program to identify and monitor leading and lagging safety performance indicators. Both of these initiatives will provide critical new information for BSEE to incorporate into the Bureau's risk management activities. Analysis of near miss reports will provide BSEE with information about accident precursors, potential hazards, and emerging safety issues. Developing a leading/lagging indicator program will allow BSEE to identify and monitor trends in operator performance. Both programs can be focused so that particular attention is given to issues related to process safety and major accident risks.

To develop a program for near miss reporting, BSEE is in the final stages of securing an agreement with an independent third party to provide programmatic and technical expertise in the development and operation of the system, as well as the collection, analysis, and distribution of the data.

BSEE should amend the SEMS regulation so that it can be applied in a risk-based fit-for-purpose manner that differentiates between facilities. SEMS should be performance-based and specific to the needs of the operation. For example the regulation should not impose the same requirements on a free standing caisson with minimal production and equipment, and a platform that has a high production rate, complex processing systems and living quarters.

BSEE concurs that the SEMS regulation should be applied in a risk-based, fit-for-purpose manner that differentiates between facilities. The operator currently has the ability to adjust the program based on the hazard analysis of specific facilities. To reduce the prescriptive nature of the regulations as they incorporate API RP 75, we have removed the ''should''/''shall'' language from 30 CFR § 250.1904. This language has also been removed from 30 CFR § 250.198(a)(3) under the recently published rule on Increased Safety Measures for Energy Development on the Outer Continental Shelf (77 FR 50856).

The overarching mechanism used by an operator to develop and implement its SEMS program provides avenues of flexibility, including the following: (1) The operator may apply the job safety analysis (JSA) to recurring events; (2) The operator has the freedom to select the individual with ultimate work authority (UWA); and (3) The operator can determine training frequency, training methodology, and the training vendor, except in specific cases where certain training requirements are specified in Section 7 of API RP 75.

BSEE has removed prescriptive language related to training from proposed sections 250.1911(c) and 250.1933(g). There is no need to prescribe each aspect of an operator's SEMS training program or how frequently an operator must conduct periodic training. The final regulatory text in 30 CFR § 250.1915 is sufficient to cover the detailed training requirements for an operator's SEMS programs. The introductory language establishes that all personnel must be trained to perform work safely. These changes allow operators to take responsibility for implementing their own training in accordance with the regulations.

The prescriptive element that was added to Subpart S in the regulations was the requirement to conduct a JSA for all tasks addressed in a SEMS. As discussed in the preamble of the proposed rule, JSAs are not covered in API RP 75. Nevertheless, SEMS maintains performance flexibility as evidenced by the discretion granted to operators to develop their employee participation plan and stop work authority programs.

Ocean Energy Safety Institute (OESI)

The DOI should establish an OESI, reporting to the Director of BSEE, through a competitive request-for-proposal process that is repeated every several years.

On May 29, 2013, BSEE announced its intent to create an OESI through a cooperation agreement. The notice is posted at grants.gov and requests proposals from qualified organizations or institutions for the establishment of an institute that will facilitate research and development, training for federal workers on identification and verification of Best Available and Safest Technology (BAST) and implementation of operational improvements in the areas of offshore drilling safety and environmental protection, blowout containment and oil spill response. All proposals were due by July 29, 2013.

The OESC recommends that a BSEE facilitated Joint Industry Project (JIP) be formed to address the improvements needed in automated well safety systems.

The Bureau not only supports the creation of the proposed JIP, but BSEE is also considering the idea of incorporating automated well safety systems into the design of OCS wells. BSEE requires the use of automated well safety systems on wells that are drilled with a subsea blowout preventer (BOP) stack, as stated in our requirements at 30 CFR § 250.442. These regulations require that the subsea BOP stack have an operational autoshear system and a deadman system when used on dynamically positioned drilling rigs. Both the autoshear and deadman system are examples of automated well safety systems. BSEE is exploring the usage of other types of automated well safety systems during drilling, well completion, well workover and/or production activities to determine whether they provide additional safety benefits and have been deemed reliable through testing, qualification, and/or usage in other operational areas. A forum such as a Joint Industry Project (JIP) could help identify additional automated well safety technologies for future evaluation.

A JIP could help identify additional automated well safety technologies for future evaluation and/or funding by the agency and or other groups. At this point in time the system with the most interest would be one that focuses on overriding human behavior and taking control of the drilling operation when personnel have been put into a risky situation; i.e., a kick has been detected downhole. In addition to requesting information on which specific automated safety topic(s) the JIP should address, BSEE will also evaluate how this JIP could best be managed. In light of the pending formation of the OESI, BSEE may consider having management of this important JIP be conducted by this organization on behalf of BSEE.

In addition, BSEE has been working with the Department of Energy's National Laboratories, through cooperative agreements, interagency agreements and JIPs, to identify and develop down-hole early kick warning systems. BSEE currently has one project underway with Argonne

National Laboratory (ANL) to test the principals of wellbore geophysics with advanced modeling techniques, and existing borehole geophysical data to monitor real-time changes in the composition and density of the drilling mud in the annulus at the bit. In addition, the project seeks to explore acoustic data routinely attenuated at the bit for early detection and warning. The ultimate objective of this project is to reduce the risk of losing well control by demonstrating whether current technologies and tools can be used to produce a low-cost early detection system (leading indicator) for subsurface drilling through experimental studies and numerical simulations.

The study will explore early well kick detection through the analysis of data sets that are routinely attenuated. It will use this information to develop a leading indicator by adapting existing technology and data to develop an early detection system for over-pressured formations at the bit. This technology will allow for detection just after the drill penetrates the formation and causes a kick, but before that kick ascends to the rig floor. Leveraging logging-while-drilling data, the project will seek to detect kicks in the area of the drill bit and pass that information to real-time data analysis software at the surface for an early warning system. Ultimately, it is hoped that this early detection could be incorporated into an automated well control system.

BSEE has also entered discussions with the Los Alamos National Laboratory to discuss the possibility of expanding the early detection effort to use higher technology applications that are more sophisticated.

It is BSEE's intent to identify any applicable early warning kick detection system as a possible triggering system for automated well control responses. Once the data is developed and analyzed from these initial studies, BSEE will use the results as a baseline for a JIP on early detection and automated shutdown systems.

BSEE should establish a process for implementing the Best Available and Safest Technology (BAST) provisions of the OCS Lands Act, through a partnership with the proposed OESI.

BSEE has been working hard to develop a process to implement BAST. First, BSEE formed an internal inter-Regional BAST team and a BAST section within the Emerging Technologies Branch, and second BSEE entered into an Inter-Agency Agreement with ANL to assist the Bureau with the evaluation and development of a functioning BAST program. BSEE has also contracted with the National Academy of Sciences (NAS) for input on what a comprehensive BAST process may look like in the future. Finally, the OESI will play an important role in informing the BAST process. Enclosures 7 and 8 contain the ANL and NAS statements of work for the BAST contracts.

BSEE should revise its regulations at 30 CFR 250.107(c). [You must use the best available and safest technology (BAST) whenever practical on all exploration, development and production operations. In general, we consider your compliance with BSEE regulations to be the use of BAST.]

BSEE supports the OESC recommendation to revise agency 30 CFR § 250.107(c) BAST regulations to remove the statement that "complying with BSEE regulations constitutes compliance with the BAST requirement." We intend to address this issue in future rulemakings most likely as an element of a proposed Subpart H production system rule.

Well Control

BSEE recognizes the importance of assessing and mitigating risks posed by underground blowouts and seafloor broaches. To this end, in 2013, BSEE plans to issue the proposed BOP rule to increase the reliability of this critical equipment. The proposed rule will upgrade regulations related to the design and repair of BOPs, incorporate a robust API standard that has industry consensus and will also include third party certification of the design and quality systems used to manufacture BOPs.

The OESC reaffirms its recommendation for a workshop on organizational and system readiness for source control. If a workshop as previously recommended by OESC is not or cannot be held, the OESC recommends that future containment exercises are designed to fully test the decision making necessary for comprehensive source control, the interaction and leadership responsibilities of the agencies and industries involved in source control efforts, and the identification and deployment of critical technical experts.

BSEE agrees that equipment deployment or table top exercises are useful tools to test the decision-making process necessary for comprehensive source control. BSEE has conducted two unannounced capping stack deployment exercises, on August 2012 with the Marine Well Containment Company and Shell and on May 2013 with the Helix Well Containment Group and Noble Energy. As part of the May 2013 exercise, BSEE invited numerous subject matter experts to observe the decision-making process and provide insight into the strengths and weaknesses of source control's interaction with the Unified Command (UC). BSEE will continue to invite experts to observe future exercises to enhance the decision making process in the source control branch of the UC. The reports of the well deployment exercises submitted by expert science observers can be found in Enclosures 9-11.

The OESC recommends that BSEE support an industry/government/academic workshop on the scientific, well planning, and regulatory issues associated with underground blowouts and seafloor broaches.

BSEE supports this recommendation and recognizes the need to identify gaps in understanding of underground blowouts and sea-floor broaches. Current technological solutions for addressing an underground blowout and a seafloor broach focuses primarily on the prevention of these phenomena through proper drilling plans and techniques. The recommended workshop will be used to identify additional solutions for these critical issues. We are presently exploring the appropriate timing and venue for the proposed workshop.

<u>Arctic</u>

BSEE understands that Arctic offshore operations involve substantial environmental challenges and operational risks. As a result, the Bureau is working with numerous government and external stakeholders to ensure that Arctic oil and gas resources are developed in a safe and environmentally responsible manner.

In January, BSEE participated in a 2013 review of Shell's Alaska offshore oil and gas exploration program. The review was ordered by Secretary Salazar after Shell experienced a series of difficulties in its Arctic operations. These difficulties included: Shell's inability to obtain certification of its containment vessel, the Arctic Challenger; deployment difficulty of the Arctic Challenger's containment dome; and serious marine transport issues associated with both of Shell's drilling rigs. The report (Enclosure 12) found that a lack of strong, direct oversight over key contractors resulted in many of Shell's problems. In its conclusion, the report (1) emphasized the critical need for coordination across federal government, and with State and local partners as well as with companies, local communities and stakeholders; and (2) reinforced the importance of an Arctic-specific model to develop Arctic appropriate safety and environmental practices.

OESC recommends that DOI develop Arctic-specific regulations and/or incorporate standards for prevention, safety, containment and response preparedness in the Arctic OCS.

BSEE is currently undertaking an expedited proposed rulemaking on this topic. As such, the Bureau is in the process of determining what regulatory actions are needed that specifically address drilling needs in the offshore areas of Alaska. We have been reaching out to stakeholders through listening posts and meetings to receive any insight they have concerning these drilling activities. We are also discussing Arctic standards with other standard setting groups.

<u>Spill Prevention</u> - adopt spill prevention standards specifically for the Arctic OCS. These standards should apply to, for example, designs for wells, pipelines, rigs, vessels, blowout preventers (BOPs) and other equipment suitable for Arctic OCS conditions.

BSEE has an Arctic Team that is reviewing the design and operating standards, including those related to spill prevention. The analysis compares existing U.S. regulatory standards to International regulatory standards and industry best practices to identify recommended standards that could potentially be adopted by the United States for future Arctic oil and gas operations.

<u>Safety Management</u> - commission a study on the human factors associated with working in the Arctic OCS to identify specific regulations needed to support development of Arctic-specific work practices, technologies and operating procedures.

"Human factors" are a critical element to safely operating in any environment. The severe conditions in the Arctic, including hours of darkness, severe cold, and relative isolation, pose some unique challenges that may not be as significant when operating in more moderate climates. BSEE is currently conducting multiple studies that focus on identifying the strengths and gaps of existing Arctic relevant regulations and operating standards. The studies will include an analysis that identifies which human factors are currently addressed in oil and gas regulations. This analysis will provide the basis for determining where additional regulation or standards development may be needed to support development of Arctic-specific work practices and equipment design.

<u>Spill Containment</u> - *adopt spill containment standards specifically for the Arctic OCS. These standards should include, for example, capping stacks, relief rigs, and other containment equipment designed for Arctic OCS conditions and positioned for prompt deployment.*

BSEE has started discussions with consensus standard bodies (such as the API, and the American Society for Testing and Materials) to develop containment standards specifically for the Arctic environment. The Standards Development Section of BSEE has also reached out to industry, through API, to encourage the development of standards for Arctic operations. BSEE is planning on discussing this at our Annual Standards Workshop to be held in November. API has also initiated discussions to reconstitute the API RP 2N committee (Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions) to update this standard, which was published in 1995. Finally, BSEE is working on an Arctic rulemaking that would require capping stacks, relief rigs and other containment equipment designed for Arctic OCS conditions.

<u>Spill Response</u> – *review Oil Spill Response Plan (OSRP) regulations, associated permitting regulations, and past approvals and revise regulations as appropriate to respond effectively to spills in the U.S. Arctic OCS, including a worst-case discharge.*

The Arctic environment is unique from other OCS areas and requires specific considerations when selecting response equipment. OSRPs for activities in federal waters offshore Alaska must now comply with federal requirements in 30 CFR 254, as well as applicable state requirements. The current requirements in 30 C.F.R. § 254 allow BSEE to ensure that available response equipment is suitable for anticipated extreme environmental conditions. Currently, BSEE can only require owners and operators to prepare to respond to spills in adverse weather conditions when it is safe to do so. BSEE is working to update these regulations in the current proposed rulemaking to better address the risk that a response may be impossible. These updates will also increase the possible response scenarios in the Arctic weather conditions through new response technologies. The notice of proposed rulemaking anticipated by the end of the year will include requirements for technologies and response capacities appropriate and effective in harsh conditions for the worst case discharges. BSEE's Oil Spill Response Division's (OSRD) Response Research Unit continues to support this goal and enhance response technologies for the Arctic environment.

BSEE in coordination with the USCG, Environmental Protection Agency (EPA), and Pipeline and Hazardous Materials Safety Administration (PHMSA), should review and assure the adequacy of Oil Spill Removal Organizations (OSROs) for the Arctic OCS.

BSEE regulations, as outlined in 30 CFR § 254, require operators to ensure that response equipment, materials, support vessels, and strategies listed are suitable, within the limits of current technology, for the range of environmental conditions anticipated at the facility. BSEE has the authority to ensure that equipment cited in a response plan, including industry owned and OSRO owned, is sufficient and capable of responding. BSEE, along with EPA, PHMSA, and USCG signed the Preparedness for Response and Exercise Program (PREP) and is an active member of the National Schedule Coordination Committee that coordinates exercise and equipment inspection activities. The PREP applies to OSROs, contractor and industry owned, that are listed in Arctic Oil Spill Response Plans. Enclosures 13-15 provide examples of a PREP report for Arctic OSROs.

BSEE should evaluate the need for Arctic oil spill equipment deployment exercise(s) prior to beginning drilling operations.

Operators are required by 30 CFR § 254.42(b) to deploy equipment annually, ensuring that each type of equipment listed in their OSRP is deployed over a triennial period. Equipment operators must receive annual hands-on training in the proper deployment and operation of response equipment under 30 CFR § 254.41. BSEE evaluates the need for any equipment deployment exercise for any region where there is drilling seaward of the coastline. Once an owner and operator enters the federal preparedness oversight system by submitting an OSRP, the owner and operator commits to maintaining the described preparedness capability through exercises, equipment maintenance, and equipment deployment and operational requirements. Enclosures 16-18 are examples of BSEE Arctic Exercise Reports.

DOI should enhance its engagement with other agencies and stakeholders, including the Alaska Regional Response Team (ARRT) and the North Slope Subarea Planning Committee, in support of ongoing development of the North Slope Subarea Contingency Plan (SCP). BSEE should continue to ensure that Arctic OSRPs are consistent with the SCP.

When reviewing Oil Spill Response Plans, BSEE ensures the tactics and priorities align with applicable SCPs.

BSEE is an active and key member of the ARRT and the SCP Workgroup that are tasked with reviewing and revising SCP documents. Moreover, BSEE actively supports DOI's National Contingency Plan. BSEE's OSRD participates in both the Alaska version of the Area Committee as well as Subarea Committees. BSEE is reaching out to both ARRT and SCP for input on a pending Notice of Proposed Rule Making.

BSEE should formalize a process with a fixed timeline for interagency review of Arctic OSRPs. Once an Arctic OSRP is approved, BSEE should make a version of the plan publicly available, wherein proprietary or confidential information has been removed.

BSEE is developing Standard Operating Procedures that include interagency review and documentation of OSRPs in the administrative record as an established part of the process. BSEE will continue to engage members of the Inter Agency Work Group (IAWG) when reviewing OSRPs for compliance with regulations. The IAWG includes all Federal Agencies that have oversight over federal lands in Alaska. Finally, BSEE is developing an external website that will host redacted versions of approved OSRPs in the near future.

If the charter of the OESC is renewed, then an Arctic subcommittee should be continued to advise DOI on issues related to implementation of the Arctic OCS recommendations presented in this document and to consider additional Arctic OCS issues, as appropriate.

An Arctic point of contact has been established within BSEE and will continue to be involved in both external Arctic related committees and interagency initiatives. Although the OESC will sunset following the submission of the final report to BSEE, the OESI will continue to address the needs of the Bureau, including Arctic oil and gas development issues. Furthermore, as noted above, BSEE has put together an Arctic Team that focuses on pertinent Arctic issues.

Again, I want to thank you, the entire Committee, and the OESC subcommittees for the thoughtful recommendations put forth in the January 25, 2013, letter and for the service you and Dr. Thomas O. Hunter provided in agreeing to be part of this Committee. The recommendations will help guide BSEE as we strive to expand our role as a world leader in safety and environmental stewardship.

Sincerely,

J.A. Watson

James A. Watson
Director

Enclosures

Safety and Environmental Management Systems (SEMS) Fact Sheet

Revisions to SEMS Final Rule (SEMS II)

The SEMS II final rule enhances the original SEMS rule, also known as the Workplace Safety Rule, that was issued in October 2010, providing greater protection by supplementing operators' SEMS programs with employee training, empowering field level personnel with safety management decisions and strengthening auditing procedures by requiring them to be completed by independent third parties.

The original Workplace Safety Rule covered all offshore oil and gas operations in federal waters and made mandatory the previously voluntary practices in the American Petroleum Institute's (API) Recommended Practice 75 (RP 75). Having a mandatory oil and gas SEMS program enhances the safety and environmental protection of offshore oil and gas drilling operations.

The SEMS II final rule expands, revises, and adds several new requirements to the existing 30 CFR part 250, subpart S, regulations for SEMS. These revisions were based on the comments received from the Notice of Proposed Rulemaking which published in the Federal Register on September 14, 2011. Operators will integrate these new requirements into their existing SEMS program, providing several key ways for personnel to help ensure safe performance of offshore oil and gas activities. The additional safety requirements contained in this final rule that were not covered in previous regulations include:

- Developing and implementing a stop work authority that creates procedures and authorizes any and all offshore industry personnel who witness an imminent risk or dangerous activity to stop work.
- Developing and implementing an ultimate work authority that requires offshore industry operators to clearly define who has the ultimate work authority on a facility for operational safety and decision-making at any given time.
- Requiring an employee participation plan that provides an environment that promotes participation by offshore industry employees as well as their management to eliminate or mitigate safety hazards.
- Establishing guidelines for reporting unsafe working conditions that enable offshore industry personnel to report possible violations of safety, environmental regulations requirements, and threats of danger directly to BSEE.
- Establishing additional requirements for conducting a job safety analysis.
- Requiring that the team lead for an audit be independent and represent an accredited audit service provider.

The elements of RP 75 that the Workplace Safety Rule originally made mandatory were as follows:

- General provisions: for implementation, planning and management review and approval of the SEMS program.

- Safety and environmental information: safety and environmental information needed for any facility, e.g. design data; facility process such as flow diagrams; mechanical components such as piping and instrument diagrams; etc.
- Hazards analysis: a facility-level risk assessment.
- Management of change: program for addressing any facility or operational changes including management changes, shift changes, contractor changes, etc.
- Operating procedures: evaluation of operations and written procedures.
- Safe work practices: manuals, standards, rules of conduct, etc.
- Training: safe work practices, technical training – includes contractors.
- Mechanical integrity: preventive maintenance programs, quality control.
- Pre-startup review: review of all systems.
- Emergency response and control: emergency evacuation plans, oil spill contingency plans, etc.; in place and validated by drills.
- Investigation of Incidents: procedures for investigating incidents, corrective action and follow-up.
- Audits: rule strengthens RP 75 provisions by requiring an initial audit within the first two years of implementation and additional audits in three year intervals.
- Records and documentation: documentation required that describes all elements of the SEMS program.

The Workplace Safety Rule became effective on November 15, 2010. Operators were required to implement a SEMS program by November 15, 2011 and must still submit their first completed SEMS audit to BSEE by November 15, 2013. The SEMS II Rule becomes effective on June 4, 2013. Operators have until June 4, 2014 to comply with the provisions of the SEMS II Rule, except for the auditing requirements. All SEMS audits must be in compliance with the SEMS II Rule by June 4, 2015.

Enclosure 2

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

[13XE1700DX EEEE600000 EX1SF0000.DSA000]

Final Safety Culture Policy Statement

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

ACTION: Notice.

SUMMARY: The Bureau of Safety and Environmental Enforcement (BSEE) issues this Final Statement of Policy to announce its expectation that individuals and organizations performing or overseeing activities regulated by BSEE establish and maintain a positive safety culture commensurate with the significance of their activities and the nature and complexity of their organizations and functions. The BSEE defines safety culture as the core values and behaviors of all members of an organization that reflect a commitment to conducting business in a safe and environmentally responsible manner. Further, it is important for all lessees, the owners or holders of operating rights, designated operators or agents of the lessee(s), pipeline right-of-way holders, State lessees granted a right-of-use and easement, and contractors to foster in personnel an appreciation for the importance of safety and environmental stewardship, emphasizing the need for their integration into performance objectives to achieve optimal protection and production.

FOR FURTHER INFORMATION CONTACT: Mr. Keith Petka, Safety and Environmental Management Systems Branch at (703) 787–1736, or by email at *SEMS@bsee.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On December 20, 2012, BSEE published a Notice in the **Federal Register** requesting comments on its Draft Statement of Policy announcing the expectation that individuals and organizations performing or overseeing activities regulated by BSEE establish and maintain a positive safety culture commensurate with the significance of their activities and the nature and complexity of their organizations and functions [77 FR 75443]. The comment period for this notice closed on March 20, 2013.

II. Summary of Comments on Draft Safety Culture Policy Statement

In response to the **Federal Register** notice, BSEE received 32 sets of comments from oil and gas companies (operators and contractors), industry associations, environmental organizations, and individuals. In the following section, we address the general comments by topic and discuss any changes made to the Policy Statement based on these comments. Comments that are not related to the notice or that are outside the scope of the policy statement are not addressed. All of the comments BSEE received are posted on *www.regulations.gov,* under docket number BSEE–2012–0017.

Comments by Topic

Support for BSEE's Issuance of Draft Safety Culture Policy Statement

A majority of commenters approved of BSEE's publication of the draft safety culture policy statement and identified it as an important starting point to initiate substantial discussions focused on improving the safety culture on the Outer Continental Shelf (OCS).

Nine Safety Culture Characteristics

The majority of commenters expressed agreement with the nine characteristics of safety culture that BSEE listed in the policy statement. Some commenters recommended modifications to the safety culture characteristics, such as the need for equipment control and integrity. In response to these comments, BSEE has altered the title of characteristic two from ''Problem Identification and

Resolution'' to ''Hazard Identification and Risk Management'' and acknowledged equipment control in characteristic four. The BSEE feels that these changes better align with the common vocabulary used on the OCS for identifying potential safety issues as well as concentrating on the inherent risk in oil and gas activities. A positive safety culture would focus on continuously appraising hazards during the various exploration and production activities while adequately directing resources to the highest risks in order to best enhance safety.

Other commenters suggested adding new characteristics such as implementation, measurement and evaluation, and reward and recognition. The BSEE believes these are valuable ideas, but are too specific for inclusion in this policy statement. It is not BSEE's intention to mandate safety culture requirements. The ultimate goal for releasing this policy statement is to outline the critical traits that are present in a positive safety culture while initiating a constructive dialogue on how regulators, industries, and the public can collaborate on improving the overall safety on the OCS. However, we will consider utilizing these concepts as we plan future strategies outside of this policy statement.

Safety Versus Production

Many commenters noted that the policy statement appears to subordinate safety to production. Most of the commenters who commented on this issue pointed out that safety and production are often viewed as being in competition with each other. All of those who commented on this issue emphasized the need to clarify that safety should not be secondary to production.

The BSEE agrees with these comments and has altered the policy statement to read, ''Each and every person involved in the wide range of activities associated with the offshore oil and gas program should emphasize the need to integrate safety and environmental stewardship into personal, company, and government performance objectives.''

Prescription of Safety Culture

Many commenters requested that BSEE refrain from mandating the adoption of a safety culture and that the policy statement not be too prescriptive. The commenters cited the need for flexibility in the adoption of safety culture and expressed the concern that the very act of mandating or prescribing safety culture activities would counteract the cultural assimilation that the safety culture statement intends to advance. It is not BSEE's intention to mandate safety culture requirements. The BSEE believes this would be counterproductive to building a positive safety culture; therefore, we are not prescribing a safety culture policy.

Differences Between Occupational and Process Safety

Many commenters stated that the policy statement should acknowledge a difference between occupational and process safety. Some commenters noted that the measures taken to advance occupational and process safety each are different: Occupational safety focuses primarily on behaviors while process safety focuses on management framework and better involves organization leaders. One commenter stated that occupational safety efforts concentrate on individual worker actions while process safety efforts concentrate on preventing high consequence, low likelihood events through engineering design.

A number of commenters expressed concern that the broad direction to adopt a safety culture is often translated into pressure on workers to avoid injuries. According to the commenters, this would occur without a concomitant requirement for a safety culture commitment throughout all levels of the organization.

The BSEE agrees with the comments that there is a difference between process safety and occupational safety. In an effort to involve all types of safety and all organization personnel, the definition of safety culture and several parts of the statement have been edited to better encompass all roles in an organization, and characteristic three has therefore been edited to read, ''All individuals take personal responsibility for process and personal safety as well as environmental stewardship.''

Lack of Environmental Awareness

Several commenters stated that the policy statement does not adequately present the need for OCS organizations to focus on both safety and environmental issues. One commenter described the link between environmental safety and process safety that is vital to the OCS safety culture. Another commenter indicated that the statement ''must clearly and consistently emphasize the importance of environmental health and safety in addition to human safety.''

The BSEE agrees that environmental protection plays a significant role in the activities on the OCS and we have edited the policy statement to reflect this importance.

Learn From Others

A number of commenters stated that other organizations and Federal agencies have already led safety culture transformations and encouraged BSEE to study their experiences. The BSEE appreciates this suggestion and is currently working to develop information sessions and workshops with various organizations that have had extensive experience with safety culture in comparable industries (*e.g.,* Federal Aviation Administration, Nuclear Regulatory Commission, Petroleum Safety Authority Norway, etc.).

Stop Work Authority

Many commenters encouraged the use of the stop work authority. They emphasized that stop work authority could be used as a tool for workers to use in preventing accidents and as a safety cultural assimilation method. Several of those commenters who advocated special mention of stop work authority within the policy statement noted that while it deserves emphasis, it also needs to be carefully described in order to prevent misuse. According to the commenters, if the stop work authority were improperly applied or guided, it could exacerbate already deteriorating conditions.

On April 5, 2013, the final rule ''Revisions to Safety and Environmental Management Systems'' was published in the **Federal Register** [78 FR 20423]. This rule mandates that all operators implement stop work authority on all OCS activities regulated by BSEE. Therefore, BSEE is not making any changes to the policy statement with regard to stop work authority.

Further Involvement

Many commenters noted that BSEE should continue the dialogue on the topic of a safety culture policy statement. The majority of these comments contained recommendations that BSEE provide further details about safety culture in a future guidance document. Other commenters stated that BSEE should engage in an ongoing dialogue with stakeholders to discuss safety culture so that continued progress could be made.

Through public comments and industry input, BSEE has identified several tools that can effectively encourage a positive safety culture on the OCS. These include:

1. Forums and workshops with industry and other agencies to discuss safety culture initiatives;

2. Establishing a research program that can identify safety areas in need of improvement; or

3. Writing guidance documents that describe best practices and case studies for safety culture advancement.

The BSEE is currently exploring these options and will look towards further collaboration with industry and the public.

III. Statement of Policy

The BSEE defines safety culture as the core values and behaviors of all members of an organization that reflect a commitment to conduct business in a manner that protects people and the environment.

It is necessary for everyone participating in the exploration, development, and production of offshore oil and gas—from a contract service provider, to the leaseholder, to the government regulator—to realize the importance of a culture that promotes safety and environmental stewardship to a vigorous and respected offshore energy industry. Each and every person involved in the wide range of activities associated with the offshore oil and gas program should emphasize the need to integrate safety and environmental stewardship into personal, company, and government performance objectives. Continued improvement in safety and environmental protection will demonstrate to the American public that access to the valuable offshore energy resources can be accomplished while respecting the environment and protecting the offshore workers.

Experience has shown that certain personal and organizational characteristics are present in a culture that promotes safety and environmental responsibility. A characteristic, in this case, is a pattern of thinking, feeling, and behaving that emphasizes safety, particularly in situations that may have conflicting goals (*e.g.,* production, schedule, and the cost of the effort versus safety and environmental protection).

The following are some of the characteristics that typify a robust safety culture:

1. *Leadership Commitment to Safety Values and Actions.* Leaders demonstrate a commitment to safety and environmental stewardship in their decisions and behaviors;

2. *Hazard Identification and Risk Management.* Issues potentially impacting safety and environmental stewardship are promptly identified, fully evaluated, and promptly addressed or corrected commensurate with their significance;

3. *Personal Accountability.* All individuals take personal responsibility for process and personal safety, as well as environmental stewardship;

4. *Work Processes.* The process of planning and controlling work activities is implemented so that safety and environmental stewardship are maintained while ensuring the correct equipment for the correct work;

5. *Continuous Improvement.* Opportunities to learn about ways to ensure safety and environmental stewardship are sought out and implemented;

6. *Environment for Raising Concerns.* A work environment is maintained where personnel feel free to raise safety and environmental concerns without fear of retaliation, intimidation, harassment, or discrimination;

7. *Effective Safety and Environmental Communication.* Communications maintain a focus on safety and environmental stewardship;

8. *Respectful Work Environment.* Trust and respect permeate the Organization with a focus on teamwork and collaboration; and

9. *Inquiring Attitude.* Individuals avoid complacency and continuously consider and review existing conditions and activities in order to identify discrepancies that might result in error or inappropriate action.

Although there are additional traits that amplify or extend these basic characteristics, these nine characteristics are foundational to the development of an effective and functioning safety culture that recognizes the need to protect people and the environment first and foremost.

Dated: May 2, 2013.

James A. Watson,

Director, Bureau of Safety and Environmental Enforcement.

[FR Doc. 2013–11117 Filed 5–9–13; 8:45 am]

BILLING CODE 4310–VH–P

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BSEE ANNOUNCES FINAL SAFETY CULTURE POLICY STATEMENT

2013-05-09

WASHINGTON- As part of the Bureau of Safety and Environmental Enforcement's (BSEE) commitment to promoting offshore safety at all levels, at all times, Director James Watson today released the Bureau's final Safety Culture Policy Statement.

The non-regulatory statement defines nine characteristics that are indicative of a robust safety culture. The policy statement will inform BSEE's regulatory approach to lead the offshore oil and gas industry beyond a checklist-inspection approach toward a systemic, comprehensive approach to compliance.

"The human factor is the critical element in offshore safety," Director Watson said. "Prescriptive regulations can reduce risks to worker safety and the environment, but they alone are not enough. Everyone working in the offshore industry must adhere to a set of core values that places safety above all else."

BSEE defines safety culture as the core values and behaviors of all members of an organization that reflect a commitment to conducting business in a safe and environmentally responsible manner. The Safety Culture Policy Statement informs the offshore community of the Bureau's safety expectations but does not create any additional regulatory requirements. The nine characteristics of a robust safety culture are:

1. Leadership Commitment to Safety Values and Actions. Leaders demonstrate a commitment to safety and environmental stewardship in their decisions and behaviors;
2. Hazard Identification and Risk Management. Issues potentially impacting safety and environmental stewardship are promptly identified, fully evaluated, and promptly addressed or corrected commensurate with their significance;
3. Personal Accountability. All individuals take personal responsibility for process and personal safety, as well as environmental stewardship;
4. Work Processes. The process of planning and controlling work activities is implemented so that safety and environmental stewardship are maintained while ensuring the correct equipment for the correct work;
5. Continuous Improvement. Opportunities to learn about ways to ensure safety and environmental stewardship are sought out and implemented;
6. Environment for Raising Concerns. A work environment is maintained where personnel feel free to raise safety and environmental concerns without fear of retaliation, intimidation, harassment, or discrimination;
7. Effective Safety and Environmental Communication. Communications maintain a focus on safety and environmental stewardship;
8. Respectful Work Environment. Trust and respect permeate the organization with a focus on teamwork and collaboration; and
9. Inquiring Attitude. Individuals avoid complacency and continuously consider and review existing conditions and activities in order to identify discrepancies that might result in error or inappropriate action.

After releasing the draft Safety Culture Policy Statement on December 20, 2012, BSEE collected comments from operators, industry associations, environmental organizations and individuals. Each one was closely examined and considered before completing the final Safety Culture Policy Statement, which is available for review today in the Federal Register Reading Room, and will be published Friday.

The final Safety Culture Policy Statement is the latest in an ongoing effort by BSEE to emphasize that the offshore industry must make safety their number one priority. Also furthering this effort was the finalization of the Safety and Environmental Management Systems (SEMS) II final rule on April 5, 2013, which enhanced the original SEMS rule, also known as the Workplace Safety Rule. It provides greater protection by supplementing operators' SEMS programs with greater employee participation, empowering field level personnel with safety management decisions and strengthening oversight by requiring audits to be conducted by accredited third-parties.

The final Safety Culture Policy Statement is available here.

More information about the SEMS II final rule is available here.

MEMORANDUM OF AGREEMENT
BETWEEN THE
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT – U.S. DEPARTMENT OF THE INTERIOR
AND THE
U.S. COAST GUARD – U.S. DEPARTMENT OF HOMELAND SECURITY

BSEE/USCG MOA: **OCS-07** Effective Date: April 30, 2013

SUBJECT: SAFETY AND ENVIRONMENTAL MANAGEMENT SYSTEMS (SEMS) AND SAFETY MANAGEMENT SYSTEMS (SMS)

A. PURPOSE

The United States Coast Guard (USCG) and the Bureau of Safety and Environmental Enforcement (BSEE) share jurisdiction to require industry to implement systematic ways of managing safety and environmental protection on the Outer Continental Shelf (OCS) with respect to oil and natural gas operations. The agencies' shared regulatory goal is for all parties involved in OCS operations to develop a comprehensive approach to safety and environmental management that provides for the necessary organizational structures, systems of accountability, and commitments to continual improvement.

The purpose of this MOA is to:

1. Establish a process to determine areas relevant to safety and environmental management within jurisdiction of both the USCG and BSEE where joint policy or guidance is needed;
2. Ensure that any future OCS safety and environmental management regulations do not place inconsistent requirements on industry; and
3. Establish a process to develop joint policy or guidance on safety and environmental management systems.

This MOA will be implemented in accordance with the Memorandum of Understanding between the BSEE and the USCG, signed on 27 November 2012. The participating agencies will review their internal procedures and, where appropriate, revise them to be consistent with the provisions of this MOA.

B. AUTHORITIES

The USCG enters this agreement under the authority of 14 USC §§ 93(a)(20) and 141. The USCG regulates offshore activities pursuant to the Outer Continental Shelf Lands Act (OCSLA), as amended, 43 USC § 1331 *et seq.,* including §§ 1333, 1347, 1348, 1356; 33 USC§ 2712(a)(5)(A); Titles 33 (Navigation and Navigable Waters) and 46 (Shipping) of the United States Code; the Oil Pollution Act of 1990, 33 USC § 2701 *et seq.*; Section 311 of the Federal Water Pollution Control Act, also known as the Clean Water Act, 33 USC§ 1321; and Executive Order 12777. Applicable USCG regulations are found under parts of Titles 33 (Navigation and Navigable Waters) and 46 (Shipping) of the Code of Federal Regulation (CFR), as well as under the National Contingency Plan, 40 CFR Part 300.

The BSEE enters this agreement under the authority of OCSLA, 43 USC §§ 1331 *et seq*. Applicable BSEE regulations are found under parts of Title 30 (Mineral Resources) of the CFR.

The USCG, within the Department of Homeland Security (DHS), regulates the safety of life and property and the safety of navigation and protection of the environment on OCS units and vessels engaged in OCS activities. In addition, the USCG regulates workplace safety and health, as well as enforces requirements related to personnel, workplace activities, and conditions and certain equipment on the OCS. The USCG is responsible for oil spill preparedness and response and conducts research related to these mission requirements. The USCG is also responsible for security regulations on OCS installations, as specified under the Maritime Transportation Security Act, and has select duties for regulating deepwater ports as enumerated in the Deepwater Port Act, as amended.

The BSEE exercises safety and environmental enforcement functions related to OCS facilities including, but not limited to, developing regulations governing OCS operations, permitting, conducting inspections and investigations, enforcing regulatory requirements, assessing penalties, and conducting research.

C. AGENCY RESPONSIBILITIES

1. **COMMUNICATIONS AND CONTACTS** – The Chief of the Office of Offshore Regulatory Programs, BSEE, and the Director of Commercial Regulations and Standards, USCG, will identify a coordinator from each agency for safety and environmental management. Each coordinator will develop and maintain a list of key contacts from each agency for the BSEE's Safety and Environmental Management Systems (SEMS) and the USCG's Safety Management Systems (SMS). These coordinators will be authorized to recruit staff with appropriate skills and knowledge to participate in carrying out the responsibilities outlined herein.

2. **JOINT POLICY OR GUIDANCE DEVELOPMENT** – The respective coordinators will hold regular meetings. The goal of these meetings is to address the purposes of this MOA as described in Section A., specifically addressing the following:

   a. 33 CFR Subchapter N and 30 CFR Part 250 Subpart S. The USCG and the BSEE will:

      i. Document and identify areas within 33 CFR Subchapter N and 30 CFR Part 250 Subpart S that may require development of joint policy or guidance that will assist regulated parties to develop and implement more effective safety management systems.

      ii. The USCG and the BSEE will develop joint policy or guidance for each area identified under sub-paragraph i of this paragraph, as appropriate.

   b. 33 CFR Subchapter F Part 96, International Safety Management (ISM) Code and 30 CFR Part 250 Subpart S. The USCG and the BSEE will determine the interface between a vessel's ISM Code Compliant SMS and an operator's SEMS program. By determining this interface, USCG and BSEE will:

i. Identify and document all areas within the ISM Code and 30 CFR Part 250 Subpart S that may require the development of joint policy or guidance.

ii. Develop joint policy or guidance for each area identified under sub-paragraph i of this paragraph, as appropriate.

3. **Joint Evaluations/Boardings/Inspections** – The respective coordinators will facilitate joint evaluations/boardings/inspections. At a minimum once per year, a joint evaluation/boarding/inspection will be conducted as follows:

   a. The joint evaluation/boarding/inspection should qualify as both:

      i. an evaluation under BSEE's regulations, 30 CFR Part 250 Subpart S, and

      ii. a boarding or an evaluation under USCG regulations 33 CFR Subchapter F Part 96 and 33 CFR Subchapter N, respectively.

   b. Whenever practicable, the BSEE and the USCG joint evaluation/boarding/inspection participants will travel together.

   c. The goals of these evaluations/boardings/inspections are:

      i. to verify that the areas identified under paragraph 2 (above) require development of joint policy or guidance, and

      ii. to develop the joint policy or guidance.

4. **Future Regulatory Projects** – The USCG and the BSEE will review and discuss all OCS-related regulatory projects related to safety management. This will help ensure that both organizations are aware of regulatory projects before the responsible agency completes them.

5. **Information sharing**– The agencies agree to share information related to their respective safety management efforts and recognize that sharing information is important for carrying out the purpose of this agreement. All information sharing should be consistent with any other applicable interagency agreements and legal limitations. Specific examples of information to be shared include:

   a. Any significant finding relevant to OCS safety and environmental management, and

   b. Results of any joint evaluation/boarding/inspection described in this MOA.

6. **Agency Training and Events**– To the extent feasible, the two agencies will provide each other's staff with an opportunity to attend training courses and any agency-sponsored events related to OCS safety and environmental management.

D. General Provisions

Nothing in this MOA alters, amends, or affects in any way, the statutory authority of the BSEE or the USCG. This MOA cannot be used to obligate, commit or establish the basis for the transfer of funds. All provisions in this MOA are subject to the availability of personnel and funds. A separate reimbursable service agreement must be established to provide for the transfer of funding for costs that result from one agency providing the other with transportation.

The MOA is not intended to, nor does it, create any right, benefit, or trust responsibility, substantive or procedural, enforceable at law or equity by any person or party against the United States, its agencies, its officers, or any other person.

This MOA neither expands nor is in derogation of those powers and authorities vested in the participating agencies by applicable law. If any portion of this MOA is found to be in conflict with the BSEE/USCG MOU, the MOU controls.

E. Amendments to the MOA

This MOA may be amended by mutual agreement between the participating agencies as described in Section I. of the BSEE/USCG MOU dated 27 November 2012.

F. Effective Date

The terms of this agreement become effective upon signature by both parties.

G. Termination

This MOA may be terminated by either of the participating agencies after providing 30-days advance written notice to the other agency.

Mr. James A. Watson
Director
Bureau of Safety and Environmental Enforcement
U.S. Department of the Interior

Date: 4/30/2013

Rear Admiral Joseph Servidio
Assistant Commandant for Prevention Policy
U.S. Coast Guard
U.S. Department of Homeland Security

Date: 30 APRIL 2013

Bureau of Safety and Environmental Enforcement
Interim Policy Document

Issuance: August 15, 2012 **IPD No. 12-07**
Effective Date: N/A
Series: 650 - Inspection and Enforcement
Title: Issuance of an Incident of Non Compliance (INC) to Contractors

Originating Office: Office of Offshore Regulatory Programs

1. **Purpose**: The policy provides for consistency in the application of the Bureau of Safety and Environmental Enforcement's (BSEE) enforcement authority by establishing the parameters by which the bureau will consider the issuance of INCs to contractors in addition to the operators conducting offshore exploration, development and production activities.

2. **Authority**: The Secretary of the Interior ("the Secretary") has regulatory jurisdiction over all entities that perform activities under provisions related to leasing of the Outer Continental Shelf (OCS) under the Outer Continental Shelf Lands Act (OCSLA) (43 USC §§ 1334 (a) and 13509b)) Under Secretarial Order 3299, the Secretary has delegated to BSEE responsibility for safety and environmental enforcement functions including, but not limited to, the authority to permit activities, inspect, investigate, summon witnesses and produce evidence; levy penalties; cancel or suspend activities; and oversee safety, response and removal preparedness. Starting in 2011, BSEE has exercised its authority over contractors by issuing INCs to Transocean and Halliburton following the *Deepwater Horizon* tragedy for violations found to have contributed to the loss of well control.

3. **Policy/Action**: Any person performing an activity under a lease issued or maintained under the Outer Continental Shelf Lands Act (OCSLA) has responsibility for compliance with regulations applicable to that activity, is obligated to take corrective action, and is subject to civil penalties for a failure to comply. As a general matter, because all operations on a lease must be performed in a safe and workmanlike manner and work areas maintained in a safe condition (30 CFR §§ 250.107(a) (1) and (a) (2)), contractors performing regulated activities can be held responsible for a wide range of conduct.

   Guidance on issuance of Incidents of Noncompliance

   BSEE will hold lessees and operators directly and fully responsible for all activity conducted under a lease issued or maintained under OCSLA without limiting its ability to pursue enforcement actions against contractors.

   While the primary focus of BSEE's enforcement actions will continue to be on lessees and operators, BSEE will, in appropriate circumstances, issue incidents of noncompliance ("INCs") to contractors for serious violations of BSEE regulations. The issuance of an INC to a contractor does not relieve the lessees from liability. In fact, in instances in which INCs are issued to a contractor, INCs will also be issued to the lessee or operator.

   BSEE will consider the following four factors in determining whether to issue INCs to contractors:

   1. The type of the violation,
      - Did the act or failure to act violate health, safety, or environmental requirements?

2. The harm (or threat of harm) resulting from the violation,
   - Did the violation directly result in, or could the violation have directly resulted in, serious injury or environmental damage?
3. Foreseeability of harm (or threat of harm),
   - Was it reasonably foreseeable that the violation could directly result in serious injury or environmental damage?
4. The extent of the contractor's involvement in the violation(s),
   - Did the contractor have control over the activity that resulted in the violation?
   - Did the contractor's act or failure to act play a significant role in the violation?
   - Did the contractor know or should the contractor have known that the activity may result in a violation?

The list above is intended to provide general guidelines for enforcement actions against contractors who are determined after a complete review of the facts to have engaged in egregious conduct. If an inspector believes that an INC should be issued to a contractor, the facts and circumstances related to the activity should be forwarded to the District Supervisor for consideration. The District Supervisor will review and validate the facts related to the activity before applying the four factors listed. The District Supervisor will document all facts related to the decision to issue any INCs. This policy statement is intended for internal agency guidance only. It is not intended to create any rights in or impose any duties on any person performing an activity under the OCSLA, or to establish any cause of action against BSEE or its employees.

4. Expiration: This IPD remains valid until superseded.

5. Contact: Doug Morris, Chief, Offshore Regulatory Programs, 202-208-3500.

J A Watson
James A. Watson, Director

AUG 15 2012
Date

Bureau of Safety and Environmental Enforcement
Interim Policy Document

Effective Date: July 15, 2013 **IPD No.: 2013-08**
Series: 640 - Operations
Title: Safety and Environmental Management System Enforcement
Originating Office: Office of Offshore Regulatory Programs

1. **Purpose.** This Interim Policy Document (IPD) establishes Bureau of Safety and Environmental Enforcement (BSEE) policy and responsibilities for Safety and Environmental Management System (SEMS) program management and implementation.

2. **Objective.** To provide national guidance specific to the responsibilities and activities of the SEMS oversight program. To ensure consistent implementation practices by BSEE personnel involved in conducting SEMS compliance evaluations, audits, and enforcement activities on the Outer Continental Shelf (OCS).

3. **Authorities.** The following statute provides BSEE with the legal authority to administer the SEMS oversight program:

   The OCS Lands Act as amended (43 USC 1334(a).)

4. **References.**

   Oil and Gas and Sulphur Operations on the OCS (30 CFR 250.1900-1929)

5. **Policy.** BSEE regulations require operators to implement a SEMS program to identify, address, and manage safety, environmental hazards, and impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing Outer Continental Shelf facilities. Although the regulations place responsibility on the operator for development, support, continued improvement and the overall success of its SEMS program, BSEE personnel involved in inspections or investigations play an important role in providing the Agency with information on the effectiveness of the SEMS program and assisting the industry in the process of continual improvement. To ensure that the Bureau provides oversight and direction to the industry in a consistent manner, BSEE issues the following guidelines:

   A. The focus of the SEMS program will be on promoting an operator-driven system that continually improves safety culture and safety practices within the industry. A collaborative and interactive approach between BSEE and the operator will help to identify and address any key gaps in the safety management systems being used on the facility. To foster this type of cooperative safety culture, BSEE will take affirmative steps to assist operators in evaluating and improving their overall safety management systems.

B. If the BSEE district personnel have concerns related to the overall safety culture on a facility or have identified apparent non-conformity in a SEMS program, the concerns and/or non-conformity should be documented in writing and provided to the BSEE District Manager and Chief Inspector. These initial observations related to a non-conformity in a SEMS plan generally should not result in the issuance of an Incident of Noncompliance (INC).

C. Information related to a facility's safety culture or potential non-conformances with the overall objectives of SEMS implementation should be relayed by the District Manager or appropriate manager to the Regional SEMS coordinator. These data will be used in evaluating the effectiveness of an operator's SEMS program and assist to identify facilities that may need additional regulatory oversight in the future.

D. INCs for SEMS programs will be generally limited to errors involving a failure by an operator to comply with a SEMS regulatory deadline, or the failure of an operator to take corrective action to resolve a non-conformance in a SEMS plan within a specified time frame.

E. An INC involving operations or equipment may be an indication of a deficiency in the design or implementation of a SEMS program. Whenever an INC is issued to an operator that relates to safety, BSEE may request the operator to review its SEMS program and determine if corrective action is needed.

F. If there are egregious safety issues at a facility or if the operator is involved in a series of incidents or near misses that present significant safety or environmental concerns, the Regional Director may require that the operator review its SEMS program and submit a corrective action to address any deficiencies.

G. The National SEMS Coordinator shall be responsible for monitoring INC, incidents, equipment failures, and near miss data for operators to determine if there is a pattern of conduct that indicates a deficiency in a specific SEMS plan or SEMS audit. The National SEMS Coordinator shall use these data in the assessment of the sufficiency of the plan or audit.

6. **Cancellation**: This IPD will remain in effect until superseded.

James A. Watson – Director

Date: July 15, 2013

INTERAGENCY AGREEMENT E12PG00045
Supplemental Pages

1. PARTIES AND PURPOSE

This Interagency Agreement (IA) establishes an agreement between the Bureau of Safety and Environmental Enforcement (BSEE) and the US Department of Energy (DOE). The purpose of the agreement is for BSEE to procure energy engineering, systems analysis**,** and technical support from the DOE Argonne National Laboratory (ANL).

2. AUTHORITY

This agreement is entered into pursuant to the authority of the Economy Act of 1932, as amended (31 U.S.C. 1535) or other statutory references and adheres to Federal Acquisition Regulation (FAR) 6.002. To the best of our knowledge, the work to be performed under this agreement will not place DOE and its contractor in direct competition with the private sector.

BSEE warrants that sufficient funding is currently available for this agreement, that the services cannot be obtained as conveniently or economically by contracting with a private source, and that it is in the best interest of the Government to provide funding to the Department of Energy, for subject work under this Interagency Agreement.

The Department of Energy will utilize an existing contract, Contract No. DE-AC02-06CH11357 with UChicago Argonne, LLC, entered into before placement of this order.

3. STATEMENT OF WORK

BACKGROUND:

The U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) is responsible for safety and environmental oversight of oil, gas, and renewable energy development on the outer continental shelf (OCS) of the United States. BSEE oversees the production and development of offshore resources in concert with other federal, state, and local agencies and in consultation with the public. The agency also enforces and regulates operations conducted on the OCS. Its functions include the development and enforcement of safety and environmental regulations; the permitting of offshore exploration, production development, and production operations; the conduct of safety and environmental compliance inspections; oil spill response planning; and the management of training and environmental compliance programs. BSEE must carefully manage national priorities related to energy development while meeting goals of increasing safety in an industry where technology is quickly advancing.

As part of this effort, BSEE is developing advanced approaches to regulatory oversight and enforcement that place greater emphasis on innovative methods such as risk based analysis and science based safety methods. To complement its existing capabilities, BSEE is requesting scientific and technical assistance from the Department of Energy, Argonne National Laboratories (DOE/ANL).

SCOPE OF WORK:

The primary focus areas that BSEE has identified to be covered under the IA are:

1. Best Available and Safest Technology (BAST) – Argonne will provide assistance working with standards organizations in setting up the BAST protocol. Argonne has the engineering capabilities to establish test facilities or processes for any BAST that is identified as potential improvements in safety and environmental protection. The model would be that BSEE would help establish the test facilities, set testing protocols, success/failure determinations, and the cost/benefit analysis. The test facilities in the future would be funded by manufacturer testing (OHMSETT Model).
2. Leading/lagging indicators and risk-based analysis – The nuclear side of Argonne has extensive experience in risk-based analyses of the nuclear industry and facilities. Argonne has effective, established models that can be modified to provide BSEE with protocols that will maximize the use of BSEE inspection resources and target BSEE resources to high-risk operations, procedures and policies. As part of this effort, BSEE anticipates the use of real-time monitoring, leading and lagging indicators and results of the near-miss analyses. A portion of this work would involve setting up methods of measuring equipment reliability.
3. Regulatory Streamlining Support – BSEE will use Argonne to prepare NEPA analyses for rules and NTLs, which will give BSEE greater control over the timing and quality of the product, thus reduce rule development time. BSEE will also use Argonne to help with review and response to comments received on rules.

These focus areas will be addressed via five major task areas:

1. Technical and environmental analysis to support safety, technology, regulatory and policy decisions, and standards development;
2. Technical foundations and support for permitting, inspection, and enforcement activities;
3. Research and development and technical reviews to support safety, technology, and oil spill prevention/response;
4. Stakeholder involvement and advanced communication methods; and
5. Systems analysis and technical support for environmental, technical and operational safety management systems.

Subtasks under the major task areas will be developed jointly by the BSEE and DOE/ANL program contacts as subtask statements of work.

TASK AREA 1: Technical and environmental analysis to support safety, technology, regulatory and policy decisions, and standards development

BSEE must comply with numerous environmental and operational laws, regulations, and Executive Orders to carry out its mission. Operational reviews, analyses and assessments are conducted by BSEE to ensure compliance with these requirements. Additionally, the oil and gas and renewable energy industries are rapidly introducing new technologies (e.g., BAST) that may not be covered by existing regulations. BSEE is regularly challenged to keep pace with this technology, and to participate and remain current in areas of standards development.

DOE/ANL will directly support BSEE on issues to address the effectiveness, comprehensiveness and timeliness of regulations based on the authority given by the Outer Continental Shelf Lands Act (OCSLA), including reviews of the regulatory processes themselves. Argonne will provide scientific background and expertise to deliver independent and industrially neutral expertise and analysis to support BSEE as BSEE reviews, contributes toward, and participates in standards development.

Argonne will assist BSEE in developing and implementing risk-based, cost-effective approaches to technology implementation, safety, regulatory analysis and assessment. Argonne will use its experience with national-level programmatic activities under the U.S. Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the Department of Agriculture (USDA), to provide expertise in qualitative and quantitative risk analysis, environmental and technical assessment and evaluation consistent with the current direction in which the agency is moving.

TASK AREA 2: Technical foundations and support for permitting, inspection, and enforcement activities

There are three regional offices (for the Gulf of Mexico, Alaska, and Pacific regions), as well as six district offices that manage field operations including permitting, inspection, and enforcement of BSEE's regulations and policies. In order to effectively prioritize this work, and keep up with the impact of new technology directions, BSEE is looking to utilize risk-based management strategies.

BSEE also operates the National Offshore Training & Learning Center (NOTLC) with specially developed curricula focused on keeping experienced inspectors current on new technologies and processes and ensuring that new inspectors are given the proper foundation for carrying out their duties rigorously and effectively.

Goals of the NOTC are to:

- Design and deliver programs that recognize and encourage the continued development of inspectors and engineers and reduce vulnerabilities.

- Develop structured technical and professional development curricula to meet the needs of a diverse audience with an emphasis on the BSEE mission.

- Build relationships with internal and external stakeholders to ensure the training and educational programs are models of efficiency and effectiveness.

Argonne will provide support to BSEE in its policy and training development activities, including support for technology assessments, feasibility studies, economic analyses, and environmental impact assessments. Additional support will include preparing and implementing guidance and training programs and designing and implementing stakeholder involvement strategies.

Argonne will work with BSEE to identify the best approaches for individual projects and challenges. The Laboratory will provide technical assistance to BSEE activities to (a) identify and assess leading/lagging indicators, (b) evaluate industry provided risk assessments, (c) plan and conduct risk-based inspections, and (d) collect and maintain commercially sensitive information.

TASK AREA 3: Research and development to support safety, technology, and oil spill prevention and response

BSEE conducts and funds innovative research to provide technical information and address problems associated with energy development and safety management on the OCS. The objectives of this research are to:

- Provide the best available and safest scientific and technical information to support decisions on the OCS safety program that could affect environmental, social, and economic conditions;

- Monitor OCS facilities, operations and technology development to determine the safety and environmental impact scenarios needed to effectively regulate these operations; and

- Collect and make available to its stakeholders information needed to analyze, discuss, and guide future decisions regarding activities on the OCS, including oil spill prevention.

Such studies support the preparation of both internal and external reports as well as technology evaluation and/or development of proposed legislation and regulations that may affect OCS activities.

DOE/ANL will provide research and support to BSEE in developing innovative and cost-effective approaches to safety and technology by employing, to the maximum extent possible, an integrated systems approach that incorporates modeling, data collection, and visualization tools for solving energy development and safety management problems. Additionally, DOE/ANL will serve as an independent expert reviewer for technology and safety analyses that BSEE is overseeing or otherwise engaged in.

TASK AREA 4: Stakeholder involvement and advanced communication methods

DOE/ANL will facilitate, develop and promote consensus building and information gathering sessions and meetings. DOE/ANL will work with BSEE to develop and implement innovative approaches to maximize the efficiency and efficacy of the agency’s stakeholder involvement processes.

TASK AREA 5: Systems analysis and technical support for environmental, technical and operational safety management systems

DOE/ANL will assist BSEE in its responsibilities for implementing management systems such as the Safety and Environmental Management System (SEMS – 30 CFR 250.1900-1929) that entails rulemaking as well as the monitoring, and review of, field management systems from multiple vendors.

DOE/ANL will assist BSEE in developing new methods and tools for experience evaluation, performance trending and assessment of management systems. This will require evaluations of hazards assessments and risk-based management practices. The new methods and tools may include computer simulation and modeling, use of information systems, database management, data trending and visualization, and possibly remote sensing and Internet applications.

4. SCHEDULE AND DISTRIBTUION OF DELIVERABLES

	Deliverable	Distribution	Due Date
A	Quarterly Status Reports	COR – one (1) digital file CO – one (1) hardcopy of the transmittal letter only	Shall be submitted quarterly beginning 30 days after the first quarter of the agreement period.
B	Other Interim and Final Reports	COR – three (3) digital file on CD and three bound hardcopies CO – one (1) hardcopy of the transmittal letter only	Upon completion of each subtasks as described in the subtask statement of work.

A. Quarterly Status Reports: DOE/ANL shall submit quarterly, a concise status report in letter format containing:

- A summary of work accomplished and overall progress made in each task and subtask under the agreement.
- A summary of any significant problems encountered during the preceding quarter, including an assessment of their probable impact on DOE/ANL's performance and statements of corrective actions taken or proposed.
- A summary of any major technical findings and interpretations during the preceding quarterly period.
- A list of any significant meetings held or other contacts made in connection with the agreement during the quarterly period, including a brief summary which outlines the subject, participants, date, location, and outcome of each such contact or meeting.
- A summary of major work activities scheduled for the next quarterly period.
- A summary of any questions or problems regarding the DOE/ANL's work requiring discussion or resolution with BSEE.

B. Other Interim and Final Reports: ANL shall submit a Draft Final and Final Report for individual subtasks as written in the subtask statement of work.

5. ADDRESSES FOR DELIVERABLES

Contracting Officer's Representative (COR) Mik Else, Office of Regulatory Programs Bureau of Safety and Environmental Enforcement 381 Elden Street, HE 3314 Herndon, VA 20170 Email: Michael.Else@bsee.gov	Contracting Officer (CO) Paula Barksdale, Acq. Management Division Bureau of Safety and Environmental Enforcement 381 Elden Street, HE 2306 Herndon, VA 20170 Email: Paula.Barksdale@bsee.gov

6. QUALITY ASSURANCE ACTIVITIES

The purpose of the Argonne quality assurance (QA) program is to establish procedures for performing high-quality work on projects and to ensure that the planned procedures are followed during the course of the work. QA procedures cover project planning, field activities, laboratory and data analysis, review of reports, documentation, and records retention. All deliverables may be subjected to thorough review by qualified technical staff members who are not otherwise involved in the project.

7. PROJECT MANAGEMENT

Dr. Dan Fraser of Argonne's Energy Engineering and Systems Analysis directorship (EESA) will be the lead principal investigator for work conducted under this proposal. He will be assisted by Dr. Joseph Braun, a senior program manager in the Nuclear Engineering Division, and other key individuals as needed from other groups and divisions. These individuals will work with BSEE to identify and define specific projects under this proposal.

For individual subtasks conducted under this proposal, Argonne will draft a Statement of Work identifying the proposed (a) scope of work, (b) technical approach or methodology, (c) deliverables, (d) schedule, and (e) budget. Argonne will work iteratively with BSEE project leader to develop a final Subtask Statement of Work.

Typical subtask organization includes a project leader, technical leads, and supporting staff. Argonne will meet with the BSEE as needed to discuss progress on individual projects. Written progress reports will be provided on a quarterly basis, and as defined by the subtask Statement of Work.

Argonne will comply with all applicable federal and state laws, regulations, and orders to protect the health and safety of workers and the public and to minimize accidental damage to property.

8. PERIOD OF PERFORMANCE

The period of performance for this effort is for five years from the latest signature on page 1 of the agreement, contingent upon the renewal of the contract between the Department of Energy and UChicago Argonne, LLC.

9. BUDGET AND FUNDING LIMITATIONS

The total cost for full performance of this effort is a Not-To-Exceed amount of $6,250,000. This agreement is fully funded.

10. TRANSFER OF FUNDS

Requests for payment or reimbursement shall be submitted no more than once monthly. The request shall cite the number of this agreement, appropriation symbol and other accounting identification codes. The payment mechanism is via the Intra-governmental On-Line Payment and Collection (IPAC). If requested by the BSEE Contracting Officer's Representative, the servicing agency must submit a summary of hours and dollars charged, location, and services provided, and any additional charges for actual costs under the IPAC.

The appropriation from which BOEM will pay for these services and the Treasury Account Symbol (TAS) is as follows:

BOEM
1. Business Event Type Code (BETC): DISB
2. Accounting codes: See page 2
3. Treasury Account Symbol (TAS)/Appropriation Code: 14X1700
4. Type of Funds/expiration: No Year
5. BPN/DUNS: 966785987
6. Employer ID (EIN): 32-0345786
7. Agency Location Code: 1422-0000

DOE
1. Business Event Type Code (BETC): COLL
2. BPN/DUNS: 175376516
3. Agency Location Code: 8900-0001

11. DURATION OF AGREEMENT AND AMENDMENTS

This agreement will become effective when signed by the parties. The period of performance will begin on the date of the last signature on the award and end 60 months later. The agreement will terminate 5 years after award, but may be amended at any time by mutual written consent of the parties.

12. MODIFICATIONS, INTERPRETATIONS, AND TERMINATION

Changes and/or modifications to this agreement may be made at any time upon mutual written consent of the parties. Modifications shall cite the Interagency Agreement identification number (E12PG00045) and shall set forth the exact nature of the change and/or modification.

No verbal statements by any person and no written statements by anyone other than the undersigned or an authorized representative as designated in writing shall be interpreted as modifying or otherwise affecting the terms of this agreement.

Either party may terminate this agreement by providing 30 days written notice to the other party. If the requesting agency cancels the order, the providing agency is authorized to collect costs incurred prior to cancellation of the order plus any termination costs.

The total value of the agreement, including termination costs, will not exceed the amount of funding obligated under the agreement.

13. RESOLUTION OF DISAGREEMENTS

Nothing herein is intended to conflict with current DOE or BSEE directives. Should disagreements arise on the interpretation of the provisions of this agreement or amendments and/or revisions thereto, that cannot be resolved at the operating level, the area(s) of disagreement shall be stated in writing by each party and presented to the other party for consideration. If agreement or interpretation is not reached within 30 days, the parties shall forward the written presentation of the disagreement to respective higher officials for appropriate resolution.

If a dispute related to funding remains unresolved for more than 30 calendar days after the parties have engaged in an escalation of the dispute, disputes will be resolved in accordance with instructions provided in the Treasury Financial Manual (TFM) Volume I, Part 2, Chapter 4700, Appendix 10, available at http://www.fms.treas.gov/tfm/index.html.

13. ACKNOWLEDGEMENTS AND NOTIFICATIONS

All reports, scientific papers, and other presentations resulting from this IA shall acknowledge the Bureau of Safety and Environmental Enforcement as a sponsor of this project on the title page of the report and the funding page of a presentation by using the following statement:

> "*This effort was funded in part by the U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement, Oil Spill Response Division through Interagency Agreement E12PG00045 with the U.S. Department of Energy, Argonne National Laboratory.*"

Each agency shall inform the other prior to issuing any news release concerning the contract.

14. SECTION 508

Section 508 of the Rehabilitation Act of 1973 (29 U.S.C. 794d) requires access to and use of information by individuals with disabilities. A deliverable for electronic data such as CD-ROMs to be distributed, are subject to Section 508 guidelines. Simplified, this means that electronic files need to be formatted so that they are "readable" by assistive technology devices such as screen readers. CD-ROMs containing files in format such as HTML, PDF, or word processor files must be assessable.

All web sites developed under this IA shall meet the technical standards of 36 CFR 1194.22, "Web-based intranet and internet information and applications".

All video and multimedia products developed under this IA shall meet the technical standards of 36 CFR 1194.24, "Video and Multimedia Products".

16. GOVERNMENT USE OF DATA

The Department of Energy shall ensure that the appropriate Rights in Data and Copyright clauses (based in Federal Acquisition Regulations 52.227-14, and 52.227-18) are included in all contracts awarded pursuant to this IA (if applicable) in order to ensure the Government reserves unlimited rights to the data.

The Department of Energy shall ensure that all data deliverables submitted under this IA shall be cleared for public use. In the event that software licenses are purchased pursuant to the Agreement, DOE shall ensure that the licenses are delivered with sufficient rights to ensure royalty-free perpetual and transferable unlimited use rights by BSEE and where applicable, unlimited public use rights.

17. CONTACTS

The following officials are the principal points of contact between the Parties in the performance of this Agreement:

Contracting Officer, BSEE
Paula Barksdale, Acquisition Management Division
381 Elden Street, HE 2306
Herndon, VA 20170
Telephone: (703) 787-1743
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Contracting Officer's Representative, BSEE
Michael Else
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Business Point of Contact, DOE
Sean Seamon
Department of Energy, Argonne Site Office
9800 S. Cass Avenue
Argonne, IL 60439
Telephone: 630-252-2077
E-mail: Sean.Seamon@ch.doe.gov

Technical Point of Contact, DOE/ANL
Daniel M. Fraser
Argonne National Laboratory
Energy Engineering and Systems Analysis
9700 South Cass Ave., Building 208
Lemont, IL 60439
Phone: 630-252-3769
Email: fraser@anl.gov

The Parties agree that if there is a change regarding the information in this section, the Party making the change will notify the other Party in writing of such change.

TRB TRANSPORTATION RESEARCH BOARD
OF THE NATIONAL ACADEMIES

August 16, 2012

NAS Proposal No. 10001156

Doug Morris
Chief, Office of Offshore Regulatory Programs
Bureau of Safety and Environmental Enforcement
1849 C Street, NW
Washington, DC 20240

Dear Mr. Morris

Enclosed is a proposal to the Bureau of Safety and Environmental Enforcement (BSEE) to provide financial support for the Transportation Research Board (TRB) "*Options for Implementing the Requirement of Best Available and Safest Technologies for Offshore Oil and Gas Operations*." The estimated cost for the performance of this activity is $500,000 as described in the attached estimate of costs for the period September 1, 2012 through August 31, 2013.

The responsible TRB staff officer for this study is Stephen Godwin (202-334-3261). Business negotiations are the responsibility of Charles Arbanas, Senior Contract Manager, Office of Contracts and Grants, (202) 334-2263.

Sincerely,

Robert E. Skinner, Jr.

Robert E. Skinner, Jr.
Executive Director

Enclosures

THE NATIONAL ACADEMIES
Advisers to the Nation on Science, Engineering, and Medicine

500 Fifth Street, NW
Washington, DC 20001

Phone: 202 334 2934
Fax: 202 334 2003
www.TRB.org

THE NATIONAL ACADEMIES

Advisers to the Nation on Science, Engineering, and Medicine

TRANSPORTATION RESEARCH BOARD

Proposal No. 10001156

OPTIONS FOR IMPLEMENTING THE REQUIREMENT OF BEST AVAILABLE AND SAFEST TECHNOLOGIES FOR OFSHORE OIL AND GAS OPERATIONS

August 2012

David P. Westbrook
Director
Office of Contracts and Grants
National Academy of Sciences
Telephone: (202) 334-2254
E-mail: dwestbro@nas.edu

for JW Henson
Stephen Godwin
Director
Studies and Special Programs
Transportation Research Board (TRB)
Telephone: (202) 334-3261
E-mail: Sgodwin@nas.edu

The National Academies consists of four organizations: the National Academy of Sciences, the National Academy of Engineering, the Institute of Medicine, and the National Research Council. The National Research Council is the principal operating agency of the National Academy of Sciences and the National Academy of Engineering. **This proposal is submitted by the NATIONAL ACADEMY OF SCIENCES (NAS), which assumes full technical and legal responsibility under its Act of Incorporation for the work to be carried out under any resultant agreement.** We are a nonprofit publicly supported organization exempt from federal income tax under Internal Revenue Service Code section 501(C)(3). The Taxpayer Identification Number is 53-0196932. DUNS Number is 04-196-4057. **Awards resulting from this proposal should be issued to NATIONAL ACADEMY OF SCIENCES and payment directed to:**

National Academy of Sciences
Accounting Office
ATTN: Cash Management Section
500 Fifth Street, NW, Room T 433C
Washington, DC 20001
Telephone: 202-334-3351 or 202-334-1476

THE NATIONAL ACADEMIES
NATIONAL RESEARCH COUNCIL
TRANSPORTATION RESEARCH BOARD

Options for Implementing the Requirement of Best Available and Safest Technologies for Offshore Oil and Gas Operations

Statement of Task:

An ad hoc committee will identify options the Department of Interior's Bureau of Safety and Environmental Enforcement (BSEE) could use for improving the implementation of the "best available and safest technologies" (BAST) requirement in the Outer Continental Shelf Lands Act. As the committee develops options, it will review those options and issues that BSEE itself already is considering; examples of which include the feasibility and appropriateness of establishing a formal industry committee to make BAST determinations about new and improved technologies; whether it will need to develop test protocols for every technology it evaluates in order to fairly compare competing technologies; how to determine economic feasibility in a manner that is independent of industry; whether it should rely on the development of consensus standards; and whether it should initiate a more vigorous process with various possible improvements to blowout preventers. The committee will identify a range of options and the pros and cons of each, but it will not recommend a specific BAST implementation approach.

In developing its report, the committee will include consideration of the following:

- Other relevant safety requirements that bear upon technologies for offshore oil and gas operations;
- Relevant reports of previous NRC committees and other organizations;
- The potential role of neutral third parties in making BAST assessments;
- The role of human factors in the safe use of technologies by industry; and
- Resource requirements of federal agencies for BAST implementation.

Project Context and Issues:

The Outer Continental Shelf Lands Act (OCSLA) Amendments of 1978 mandate that the Secretary of the U.S. Department of the Interior (DOI)

. . . require on all new [offshore] drilling and production operations and wherever practicable, on existing operations, the use of the best available and safest technologies which the Secretary determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

Following the 1978 Amendments to the OCSLA, DOI sought advice from the NRC on how to implement the BAST requirement. A 1979 Marine Board report outlined three possible options for implementing the BAST requirement, which could build upon each other:

1. Minor modifications to the existing strategy of working with and through industry to improve technical standards and practices;
2. A procedural approach that would ensure industry use of BAST in frontier or "high-risk" areas (government agencies would take the initiative in assessing risks, considering possible new technologies and evaluating their costs independently of the decision process on permits, regulations and orders);
3. A BAST standards development program in which the government would evaluate and develop new technologies and require their use through performance standards.

With each advancing option the public resource requirements for personnel and R&D funding would increase.

DOI's efforts to date have included (a) a technology assessment and research (TA&R) program that has subsequently produced hundreds of technical reports on safety and environmental technologies and practices in offshore operations, (b) regional technical committees of federal staff who met with outside experts in an effort to stay abreast of BAST developments and identify areas of improvement for standards and regulations, and (c) working with industry to develop consensus standards. The federal technical committees reported to a national committee on an annual basis, but apparently this activity waned over time.

The findings of various analyses carried out by the NAE/NRC and other organizations of the causes of the Macondo well-Deepwater Horizon incident in 2010 have raised questions about the adequacy of DOI's implementation of the BAST mandate. Issues of concern include, among others, the performance of blowout preventers, barriers used during temporary abandonment of wells, and hydrocarbon flow detection technology. In light of such concerns, BSEE is currently considering options for improving the implementation of the BAST requirement. Admiral Watson, director of BSEE, has approached the NAE/NRC with a request for advice regarding options for improving the implementation of the BAST requirement.

Work Plan:

The committee will meet three times. Data-gathering sessions will be held during the first and second meetings. The committee will be briefed by BSEE staff on the issues the bureau is considering and evaluating regarding BAST implementation. In addition, presentations will be invited from industry on BAST issues, including drilling companies, technical support contractors, suppliers of technologies, industry associations, and others. Presentations will also be invited from experts on lessons learned from the implementation of technology requirements in analogous situations, such as "best available control technology" determinations for compliance with the Clean Air Act and Clean Water Act and technical feasibility and economic practicality determinations for corporate average fuel economy (CAFE) standards. The committee's information-gathering sessions will be open to the public. A final meeting will be held in closed session for the committee to deliberate on its report.

The committee will provide a letter report with its initial reactions to BSEE's proposals to implement BAST within 6 weeks of its first meeting. A complete report (prepublication manuscript) containing the committee's findings will be provided within 9 months of award. A final published report will be provided within 12 months of award.

Project Audiences and Impact:

The committee's guidance is primarily intended to assist BSEE in selecting among policy options to enhance implementation of the BAST requirement, but the committee's report could also be influential in Congress.

FEDERAL ADVISORY COMMITTEE ACT (FACA)

The Academy has developed policies and procedures to implement Section l5 of the Federal Advisory Committee Act, 5 U.S.C. App., Section 15. Section l5 includes certain requirements Regarding public access and conflicts of interest that are applicable to agreements under which the Academy, using a committee, provides advice or recommendations to a Federal agency. In accordance with its Congressional Charter and the requirements of Section 15, the Academy must provide independent, unbiased advice without actual or perceived interference or management of the outcome (findings and recommendations). Therefore, the Academy requires the right to publish all unclassified materials without any restriction over content and release, including any restriction that may require prior approval from the sponsoring agency.

In accordance with Section l5 of FACA, the Academy shall submit to the government sponsor(s) following delivery of each applicable report a certification that the policies and procedures of the Academy that implement Section 15 of FACA have been substantially complied with in the performance of the contract/grant/cooperative agreement with respect to the applicable report.

PUBLIC INFORMATION ABOUT THE PROJECT

In order to afford the public greater knowledge of Academy activities and an opportunity to provide comments on those activities, the Academy may post on its website (http://www.nationalacademies.org) the following information as appropriate under its procedures: (1) notices of meetings open to the public; (2) brief descriptions of projects; (3) committee appointments, if any (including biographies of committee members); (4) report information; and (5) any other pertinent information.

Estimate of Costs:

It is estimated that the full cost of the activities described above will be $500,000 as illustrated in the attached cost estimates for the period September 1, 2012 through August 31, 2013.

Jim Watson

Director, BSEE

Director Watson:

At your request I observed a portion of the Noble Energy/HWC exercise in Houston on May 3, 2013. In light of the weather delay, I only attended one day of the exercise and observed only the flow engineering operations for well control. My emphasis was on the technical basis for decision making and the maturity of the analysis to support decision makers. I offer the following observations:

1) The capability of BSEE to understand source control has been significantly enhanced. The methodology and information flow is becoming better formulated and more technically credible.
2) The capability of operators (or at least this operator) to manage source control is also much better developed and has been strengthened considerably or at least the capability has now been applied to well control.
3) A broader and deeper technical review beyond my brief interaction is needed to strengthen the scientific basis and start to build confidence beyond the operator-BSEE circle.
4) The technical information package to support decisions about well control is becoming clearer and better developed. For example, the expected pressure-time history following shut-in is becoming a primary vehicle for decision support.
5) The supporting arguments for decision packages need more work but good progress is being made.
6) The pressure-time information would be enhanced by a) supporting information on the accuracy and validity of the pressure predictions b) a broader range or band on the expected well response, and c) some metrics and supporting information on time to act, for example, how long shut-in can be maintained without irreversible damage and loss of flow control through the formation.
7) The situation for non-capable wells that require cap and flow is much more complicated and needs a lot more development
8) Establishing methods of analysis, formats, and procedures is important but does not necessarily establish confidence for decision makers. Exercises like this provide the important discussion between BSEE and the operator which are essential to establishing confidence. More exercises focused only on source control should be held with more if not all operators.

9) Third party observation, evaluation, and validation would enhance the methodology and help build confidence.
10) In the ideal case, BSEE and the operator should be the primary resource to support decision making. The response organizational structure and information flow should reflect this.
11) The Incident Command should reflect a stronger role for source control in the response team structure and not have it subordinate to operations. It is the essence of the response. The NIC should also have a clear and direct link to the expertise necessary to support decisions especially in source control.
12) The determination of well flow is always problematic due to regulatory and legal concerns but it needs to be as transparent as possible as early as possible. It should be understood by all parties that when shut-in is complete, the well flow will be established. Provisions should be made in capping stacks to make this determination.
13) When the methodology for well control is mature and incorporated into the decision making process, a status briefing should be made to national decision makers who might be involved in a major response.

I have other comments outside of source control relating to the expected removal of LMRP's and better more assured delatching. In addition, some beforehand thought should be given to the role of outsiders in a real response and how they would be incorporated into the decision process.

I would be glad to discuss any of the above topics whenever needed.

Sincerely,
Tom Hunter

Feedback after participation in

HWCG 10k Capping Stack Deployment Exercise

and Fluid Flow Modeling Discussion

Background:

The Director of the Bureau of Safety and Environmental Enforcement (BSEE) invited me to join the Science Observer Team to witness the Noble Energy Inc. /Helix Well Containment Group (HWCG) 10k Capping Stack demonstration, and participate in a discussion on modeling of fluid flow from reservoir through wellbore to surface under various scenarios to prevent disasters from uncontrolled oil/gas wells. The Science Observer Team met in Katy, Texas on May 3, 2013.

No clear-cut directives, guidelines or reading material was given to me prior to my visit to Katy, Texas, regarding the offshore demonstration and the modeling efforts on fluid flow by Noble Energy Inc. For the benefit of the BSEE, however, I felt it worthwhile to document my feedback in the form of comments/observations on the Noble Energy's preparedness to a handle a well blowout leading to oil spill with possible severe consequence to human lives, and damage to equipment, property, and environment.

Due to bad weather on May 4, 2013, the HWCG 10k Capping Stack demonstration was postponed, but the discussions on the capping stack and the fluid flow from reservoir through wellbore were held as planned on Friday, May 3, 2013 at the Petroskills Conference Center Facility. I enjoyed the lively brainstorming session that went all day with the active participation from Noble Energy, BSEE and the Science Observer Team members, but the amount of efforts put in on various aspects of capping stack and modeling of fluid flow work was overwhelming especially because of the limited time available to cover it all.

Scope:

The discussions focused mostly on the geology, geophysics and modeling of fluid flow from reservoir through wellbore, and briefly on the Source Control Organization and the interaction with Noble Energy teams during the capping stack demonstration. Therefore, I will keep my comments to only the modeling of fluid flow from reservoir through wellbore to surface, and this is especially important because the results of modeling play a critical role in defining wellbore integrity and well source control activities under various flow conditions including those of well blowout.

Objective: The objective for the Science Observer Team members was to review the modeling work of fluid flow from reservoir through wellbore by the Flow Engineering Group, consisting of mostly Noble Energy staff with some support from staff from Add Energy and BSEE, and assess the adequacy of process and tools to prevent/control a well blowout situation.

Introduction:

It is really a milestone in the history of offshore operations for the 22 or so deep-water operators in the Gulf of Mexico to form the Helix Well Containment Group (HWCG) with the collective goal of preparing for quick response to a subsea spill to protect employees, communities and the environment by sharing technical expertise and resources. The HWCG has developed a deep-water well-containment response system capable of being deployed in the event of a deep-water spill.

For this exercise, Noble Energy Inc. was to conduct the capping stack deployment demonstration following the modeling of fluid flow from reservoir through wellbore to surface. The Flow Engineering Group, which included professionals mostly from Noble Energy with some support from Add Energy and BSEE, did the work of characterizing the reservoir and modeling fluid flow using various available software packages. They deployed the OLGA (transient flow) and Prosper (steady state flow) models for fluid flow and pressures through wellbore, GAP model for fluid flow and pressures through surface gathering network, and MBAL for reservoir simulation. However, of the two well models, the Flow Engineering Group preferred to use OLGA to obtain accurate values of well shut-in pressures.

Comments/Observations/Recommendations:

1. The Flow Engineering Group (Noble Energy Inc. in collaboration with staff from BSEE and Add Energy) has used well-known industry simulation software packages for well and reservoir to evaluate various scenarios and conditions including those of well blowouts. The group has done a credible job of evaluating various scenarios of wellbore and reservoir to provide better understanding of well blowout potential and to help develop procedure(s) to handle a blowout in order to minimize, if not eliminate, the risk of subsea spilling of hydrocarbons with possible severe consequences to human life, equipment and environment. However, the presentation was not well planned/organized making it harder for the Science Observer Team members to review the entire work for adequacy and offer meaningful comments.

   It is important to note that the petroleum industry as a whole has the tools to model blowout scenarios based on available information. I believe that BSEE is now trying to establish a set of approved operational procedures for each offshore operator to follow to ensure well integrity during handling of the well blowout.

2. The present set-up calls for two reservoir engineers from BSEE to be embedded within the Flow Engineering Group (Noble Energy Inc.). The Flow Engineering Group is responsible for conducting detailed assessments of geological and geophysical data needed to characterize the reservoir, especially around the wellbore, and conduct simulations of fluid flow from the reservoir through wellbore to surface for well design and procedure to handle a well blowout. Having two BSEE engineers in the Flow Engineering Group is one way to ensure compliance by individual operators to follow an approved procedure. Another alternative may be for BSEE to have its own Reservoir Engineering Group to carry out an independent study to serve as a check against the results of a similar study by individual operators to avoid any chance of any inadvertent error creeping in or biased reporting.

3. Since modeling of fluid flow from reservoir through wellbore to surface forms the basis for well design and the procedure to handle well blowout by being able to either shut-in or flow and capture, it is imperative that modeling work be assessed for its technical soundness by the representatives from industry, academia and the government agencies.

4. BSEE should expand the Science Observer Team to include members from the industry, academia and government agencies to review the modeling work by Flow Engineering Group (Noble Energy Inc.). BSEE should ask the Flow Engineering Group to prepare a report of the modeling, presenting all the input data, models' description, their validation by way of history matching, and the forecast/results. The report does not need to include any proprietary data, but the presentation at the meeting should include the data and the results for in-depth review. BSEE should circulate the report among the Science Observer Team members prior to the meeting so they have time to review the work and actively participate in the discussions.

5. The Flow Engineering Group has developed a smart soft shut-in pressure response curve to check out the well integrity under various fluid flow and pressure conditions. However, to make the plot more useful and reliable, it should also check the pressure performance of some of the historical blowout wells, if possible.

6. A practical Resource Control Response Plan, including Source Control Organization Structure, incident notification protocol, and other related setups already exists, as well as

the procedure to initiate necessary actions by various groups, such as Relief Well, SIMOPS, Containment Operations, Flow Engineering, and Flowback.

I appreciate the opportunity to serve on the Science Observer Team. If there is a need for further discussion, I would be glad to participate so long as it does not take too much of my time, as currently I am a part-time employee of the U.S. Geological Survey working on the Carbon Sequestration and Associated with CO2 EOR project work.

Science Observer Team member

Dr. Mahendra K. Verma
Research Petroleum Engineer
Eastern Energy Resources Science Center
U.S. Geological Survey – U.S. Department of the Interior
17842 Wildwood Creek Road
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Email: mverma@usgs.gov

May 22, 2013

As requested attached is my documentation of the drill over the last two days as well as my observations and recommendations. With no Terms of Reference or "Audit Protocol" provided, I used my judgment in terms of actively engaging with the drill participants (the instructions from Noble Energy were to simply observe and not discuss/intervene in the drill). While I did not intervene in the drill I did talk with the participants to understand their thought process and gain needed background.

It is unfortunate that I have to leave this afternoon, but the visit of Director Watson and Secretary Jewell to the LLOG operations offshore in the GOM on the Ensco 8502 is a significant event for LLOG, and my management would like fo rme to be offshore and assist with the visit. I hope my notes and observations are what you were looking for and provides a good background to the other members of the "Science Observation Team" who will arrive this evening. I do not have their names or contact info if you could forward this emai lto them I would be grateful.

Joe Levine

Wednesday 5/1/13
8:40– Arrived at Petroskills – Checked in – name was not on the approved list – took 50 mins to gain approvals and security pass.

Learning – Ensure 'Science Observer Team" are listed on the approved drill participant list.

9:30 AM Escorted to Flow Engineering Group – Received Well Status Briefing from Nick Lirette (Noble Energy) Flow Engineering Group Supervisor.

10:25 AM - Due to projected weather issues the stack deployment activity is at "Stand Down" – projected weather conditions for transport and deployment are not within the deployment conditions window. In addition other work groups (relief well, etc. have also been stood down). Flow Control is not at Stand Down but will continue to develop the detailed Soft Shut-in Procedure including the range of potential pressure response outcomes.

Action Items \ Objectives for the team (Weds) :

- Populate updated information injects into the WCST (Well Control Screening Tool)
- Update & Analyze WCST
- Brainstorm Upper and Lower Pressure Profiles
- Develop Soft Shut-in Procedures with Pressure Plots

1:-00 PM – Framing Discussion Notes

Fluid Gradient Discussions. Reviewed which sands can produce the lowest fluid gradient – which is all sands in the interval minus the C&D Sands.
Is this a reasonable assumption? Yes. C&D are the deepest sands in the exposed sand series, which pore pressure gradients indicate is one system. Thus, the lowest pressure gradient (15.5 Vs. 15.7-16.2 PPG) will be the last to flow. Under initial (early in the event) conditions the combined flow from all the sands minus the C&D wet sands is a conservative assumption that will yield the lowest practical fluid gradient for early flow modeling. As reservoir modeling indicates a lower pressure gradient in the upper sands in the series (both oil and water) over time the wet C & D Sands will then be added to the flowing sands contributing to the overall fluid gradient tin the well.

Reviewed the Noble Engineering broaching study in light of the drill information (Study is attached). Study covers the failure of the 9 3/8" liner with a subsequent broach of the shoe at the 14" casing string. Agreed with the studies, assessment that there are no issues with a failure of the 9 3/8" casing and any subsequent broaching at the 14" casing shoe, subsurface formations can absorb the underground cross flow with no potential to broach to the surface. Also discussed the broaching potential of the 16¼" casings as well as the sands below the 18" casing shoe. For the event to escalate to this condition the 14" casing must fail.

Discussed what conditions could lead to a failure of the 14" casing string. As long as the 14" casing has the expected burst and collapse integrity there should be no issues with shut in – team could not develop downhole conditions where the 14" casing failed under collapse or burst. Considered other scenarios where the 14" may fail – bottom line only defects in the 14", failed casing connections, a leak in the seal assembly or wear in the 14" from prior drilling operations, could lead to a failure of the 14" casing. AN y of these failure modes would require analysis of secondary failure mechanisms of the outer shallower casing strings (a) the 13 3/8 x 16 ¼ " Expandable ("16 ¼ -Expandable), (b) the 16 ¼" casing, or the 18" casing liner. Team quickly made the assessment that any exposure of casing strings shallower than the 18" casing shoe has a high enough probability of a seafloor broach and no further analysis is needed.

JML Observations –

(1) These were quality discussions that were conducted with the "Operator" (Noble Energy & other HWCG Mutual Aid Staff) and BSEE staff in different discussion groups. The larger Flow Engineering staff present in the room participated to varying degrees.

(2) The pre-drilling broaching study only addressed failure of the 9 3/8" liner and exposure of the sands behind that liner. The pre-drilling study did not address failure of the 14" casing string – which is OK since this is a very unlikely event. However, the team made a judgment call (with the BSEE staff) that the broaching risk up to the base of the 16 ¼" casing was also acceptable. This assessment was based on the independent BSEE broaching evaluation made prior to drilling. Observed no action to obtain this assessment and re-evaluate this assessment using the actual data from the well. Probably OK, but should be checked.

1:45 PM – Brainstorming Session -.

Prior to the "outcomes" discussion – team reviewed the "end in mind" which is to list the potential outcomes in order to assess the conditions that would need to be considered in developing the "Red Lines" that constitute the operating envelope for a successful shut in of the well by the capping stack.

Possible Shut-in Outcomes – Unsorted in order of discussion

- Assumed fluid gradients used in the Model are incorrect = higher or lower pressures
- Gauges on stack are wrong = higher or lower indicated pressures
- Large reservoir with water drive exceeding expectations = higher pressures
- Small reservoir with depletion drive. = lower than expected pressures
- Wellbore bridging giving lower pressures.
- Wellbore has full integrity, nothing taking fluid during shut-in. = expected outcome.
- 9 3/8" fails exposing sands above TOC
- 9 3/8" fails exposing all sands within open hole behind the 9 3/8" casing.
- 14" casing wear results in wellbore failure in collapse while flowing at WCD.
- 14" wear (no collapse) but 14" fails when shut in due to burst loads.
- 16 1/4" shoe pressure is limiting factor for soft shut-in. [red line]
- Large reservoir with water drive with well bore bridging.
- Casing connection leak in any string.
- Lower sands bridge over, upper sands still flowing.
- Lowest sands fracture below 16 1/4" casing.
- Max pressure acceptable is 14" burst pressure at pressure gauge. [red line]
- 14" seal assembly failure with mud in 14" x expandable annuals [possible red line?]

From these potential outcomes the team developed two scenarios that would define the upper and lower "redlines" pressure verses degree of wellbore shut-in that would put the well at risk of a seafloor broach and would require the well shut-in to be halted or perhaps even reversed (i.e. well reopened). Scenario #1 is a high pressure scenario resulting in burst of the 14" casing, and #2 is a low pressure scenario resulting in collapse of the 14" casing string leading to a broach of the 16 ¼" casing shoe and subsequent exposure of the sands below the 18" casing shoe.

> *JML Observations – The brainstorming discussion on potential outcomes went well, and the team members that participated in the separate framing discussions were able to share their discussions with the larger group. This gave the modeling staff an appreciation of the outcomes that would need to be evaluated by modeling specific scenarios. In subsequent discussions with the Flow Engineering Group Supervisor I learned that there was no real plan or protocol followed to develop the potential outcomes and subsequent modeling work; "This is just how I like to work" . JML Recommendation is to capture this process at a high level and incorporate into the Flow Engineering protocol of the Source Control response Plan.*

To verify/develop these load lines as well as develop expected pressure loads during wellbore shut-in to reflect likely scenarios the following models were developed.

- Large reservoir with water drive and wellbore maintains full integrity – maximum pressure line
- Most likely reservoir conditions with wellbore maintaining full integrity – likely potential outcome.
- Most likely reservoir conditions, 9-3/8" liner removed, fracture at 14" shoe – likely potential outcome
- Most likely reservoir conditions, 9-3/8" and 14" removed, fracture at expandable shoe – less likely outcome, but possible.
- Small reservoir conditions, depletion drive, 9-3/8", 14", and expandable removed, fracture at 16-1/4" shoe.
- Red line upper boundary - 14" burst pressure @ pressure gauge.
- Red line lower boundary – 18" shoe fracture pressure with reasonable fluid gradient.

For the operating envelope displayed above P=Pressure T=Time and CP=Choke Position.

Late afternoon discussion centered around the role of the Flow Engineering team. Is the role to simply determine potential outcomes and then provide modeling information associated with those outcomes to the larger Source Control Organization (which was the view of many particiapnts). Or is it also the role of this team to provide recommendations on “next steps” in the event the shut-in response pressure profiles exceed the envelope and approach the “redlines”.

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Thursday 7AM – Work continued developing the models listed above and preparing the formal operating evelope (chart) as well as adding details to the specif procedures.

Objectives (Thursday):

1. Generate shut in curves
2. Write detailed soft shut in procedures & review with Well Control team.
3. Develop Presentation for “Science Observers”

Observed numerous ideas that were outside the bounds of the Flow Engineering group that came up in discussions. Examples: - Review of the seismic data indicates likely zones on the seaflorr where the seafloor could be potentially broached. Would be a good idea to check and ensure a relevant Shallow Hazards data set exists to serve as a baseline reference in the event broaching is suspected and subsequent Shallow Hazards surveys are run. Real examples as well as most modeling indicates the time from initial broach subsurface to actual expulsion on the seafloor can be very long. Observer question – was this request/idea submitted to other work groups and if needed as a resource request? “No – those groups stood down, but if they were running I assume they would have this covered." *JML Recommendation – reinforce to the Section Chiefls and unit leaders to instruct their team members to forward all options and ideas to the relevant groups and potential resouce needs to section chiefs.*

Thursday 1:30 PM - Initial draft of the "Soft-Shut-in Pressure Response Curves have been developed and are shown in the attached spreadsheet. The "14 Inch Casing Burst" and " 18" casing shoe Broach" scenarios are shown along with the curves for the other scenarios listed above. The curves are in three stages, (1) closure of the BOPs across the main bore of the capping stack with the two side chokes full open – total time to close at ~1 minute, followed by a ~5 min period of no further closure activity, then (2) Closing of Choke #1 over a 9 minute period (9 revolutions to close the choke at 1 ROM), then no activity for ~10 mins and then (3) closing of the second choke over nine minutes at 1 RPM. At each stage the pressure response for the scenarios considered is displayed.

Team spent the remainder of the Thursday session working up the specifics of the soft shut-in protocol.

JML Opinions –

- *The Flow Engineering team did excellent work, I really liked the process and protocol they used that is captured above. <u>Recommendation:</u> The Flow Engineering Group Supervisor should capture at a high level this protocol and incorporate into the post drill review to share with the larger HWCG member companies.*

- *I do have a concern about the interaction of this team with the larger Source Control group especially during the execution of an actual shut-in.*

    - *The Flow Engineering group should not only develop the curves and model data but also be intimately involved in the real time evaluation of an actual shut-in operation. Perhaps even merged/embedded within the Containment Operations Group(s) – see Source Control Org Structure.*

    - *Most participants see their role to model, monitor and predict outcomes and feel the real time data interpretaion and subsequent response options are to be left up to other Source Control groups. Since these drills typically do not continue beyond the initial two day response and do not simulate actual deployment and shut-in operations, testing the interaction and response of the Source Control organizations under "capping conditions" does not occur. A good idea would be to conduct future drills with scenarios devleoped further forward in the response time sequence. Start on day four versus day 1 and use downhole simulators to model capping events to test this phase of the operation and interaction between response groups and sub teams .*

- *The attached Well Intergrity Assessment contains a flow chart of the process including the steps followed and covered above. The execution part of the well capping process includes steps to monitor the pressure response s the well is shut in and ensure the pressures at th estack are within the "defined conditions" or pressure vs time/choke position shown above. The response sequence associated with the actual shut-in of the well (as shown in the lower half of Appendix A in the attached Well Intergrity Assessment) is rather simplistic and assumes good communication between the sub-teams within Source Control – based on my observations of this drill – such communication should not be taken for granted and should be evaluated in future drills. Since other groups within source control were at "stand down" during this phase of the drill the interaction between the Source control sub-teams could not be observed.*

<u>Use of the Well Conainment Screening Tool (WCST)</u>

The WCST one method available to operators to demonstrate to BSEE that the well design enables containment in the event of a Worst Case Discharge (WCD). It is a screening tool, it is not a rogorous design check and is not required for an APD (Application Permit to Drill) to be apprvode by BSEE. It is simply a means to demonstrate the containment potential of a specific well design. I was asked to evaluate the use of the tool in the planning and modeling process to devleop the Flow Engineering group response/role in the drill.

In my view the WCST was used properly to screen various initial what-if scenarios given the actual wellbore conditions in the as drilled well to verify containment under a range of scenarios for both primary as well as secondary casing strings. Once these scenarios were identified the detailed modeling using Prosper (for reservoir performance,) GAP for flow modeling incorporating the capping stack and flow back interfaces, and OLGA for the transient analysis was conducted to devleop the pressure-time response curves for the various shut-in scenarios. The WCST is a conservative approach to indicate where potential problems may occur with respect to containment. It is conservative in it's assumptions and when used properly can quickly eliminate scenaios from further evaluation based on "passing" the WCST.

Kirk – If BSEE elects to continue the use of the "Science Observation Team" I recommend a terms of reference for the team be created, with guidance on areas the team is to concentrate their efforts. It also would be good for the team to meet via conference call prior to the drill and discuss, schedules, documentation, hand-off protocol etc.

Enclosure 12

REPORT TO THE SECRETARY OF THE INTERIOR

REVIEW OF SHELL'S 2012 ALASKA OFFSHORE OIL AND GAS EXPLORATION PROGRAM

MARCH 8, 2013

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I. Introduction

Last year, Shell attempted a long-planned exploratory drilling program offshore Alaska in the Beaufort and Chukchi Seas. Shell's goal for the summer drilling season was to confirm a major discovery of oil in commercially-viable quantities in the Alaskan Arctic Ocean.

Shell was not able to achieve its goal and did not complete any exploration wells last summer. The company experienced major problems with its 2012 program, some of which have been well-publicized. Shell's difficulties have raised serious questions regarding its ability to operate safely and responsibly in the challenging and unpredictable conditions offshore Alaska. As a result, Secretary of the Interior Ken Salazar ordered this review of Shell's 2012 Alaska offshore drilling program in the Beaufort and Chukchi Seas. The purpose of this review is to assess, at a high level, Shell's performance across all aspects of its 2012 Alaska offshore exploration program, identify key lessons to be learned from Shell's experience, and make recommendations applicable to any future exploration drilling operations that may be proposed for the Arctic Outer Continental Shelf (OCS). The Secretary directed that this report and its accompanying findings and recommendations be completed within 60 days.[1]

This review has confirmed that Shell entered the drilling season not fully prepared in terms of fabricating and testing certain critical systems and establishing the scope of its operational plans. The lack of adequate preparation put pressure on Shell's overall operations and timelines at the end of the drilling season. Indeed, because Shell was unable to get certified and then deploy its specialized Arctic Containment System (ACS) – which the Department of the Interior (DOI) required to be on site in the event of a loss of well control – the company was not allowed to drill into hydrocarbon-bearing zones. Shell's failure to deploy the ACS system was due, in turn, to shortcomings in Shell's management and oversight of key contractors. Likewise, additional problems encountered by Shell – including significant violations identified during United States Coast Guard's (USCG) inspection of the *Noble Discoverer* drilling rig in Seward last November, the lost tow and grounding of the *Kulluk* rig near Kodiak Island in late December, and violations of air emission permits issued by the Environmental Protection Agency (EPA) – also indicate serious deficiencies in Shell's management of contractors, as well as its oversight and execution of operations in the extreme and unpredictable conditions offshore of Alaska.

Although Shell's difficulties prevented the company from fully executing its drilling plans last summer, the company successfully completed some important elements of its drilling program. In particular, Shell succeeded in drilling "top hole" sections of two wells in the Arctic Ocean, and it did so safely without any significant injuries to workers or spills. Shell employed weather forecasting and ice management systems that enabled it to respond effectively to changing sea ice conditions, including the encroachment of a major ice floe on Shell's Burger A well site in the Chukchi Sea. Shell also coordinated well with Alaska Native communities and subsistence hunters, even under circumstances that delayed its drilling program in the Beaufort Sea.

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1 Department of the Interior, "Secretary Salazar Launches Expedited Assessment of 2012 Arctic Operations," January 8, 2013. http://www.doi.gov/news/pressreleases/secretary-salazar-launches-expedited-assessment-of-2012-arctic-operations.cfm

Because of the difficulties that Shell encountered in conducting its drilling program during the summer of 2012, the review team recommends that Shell make certain affirmative showings before it is allowed to resume its drilling program in the Arctic. Those undertakings are set forth below. In light of Shell's announced pause in its Alaska offshore program, in order to "prepare equipment and plans for a resumption of activity at a later stage," DOI expects that Shell will be able to complete these undertakings on a timely basis and in advance of its next proposed drilling season.[2]

1. **Development of a Comprehensive and Integrated Operational Plan**. Shell should submit to DOI a comprehensive, integrated plan that describes its future drilling program and related operations, including detailed information about the program's vessel and equipment configurations, the overall preparation schedule including contractor work on critical components, mobilization schedule, in-theater drilling program objectives and timelines for each objective, preparation and staging of spill response assets, and plans for demobilization and offseason repair and maintenance following the drilling season.

2. **Third-party Management Systems Review**. Shell should commission and complete a full third-party audit of its management systems, including, but not limited to, its Safety and Environmental Management Systems (SEMS) program, with particular focus on ensuring that the management and oversight shortcomings identified with respect to all aspects of the company's 2012 operation have been addressed and that the company's management structure and systems are appropriately tailored to Shell's Arctic exploration program.

DOI has been – and continues to be – supportive of industry's efforts to evaluate the offshore oil and gas resource potential on the Alaskan OCS. The Department has insisted, however, that activities proceed with caution and respect for the extreme and unpredictable conditions found offshore Alaska. This review, and the recommended undertakings expected of Shell before it returns to exploration activity in the Beaufort and Chukchi Seas, are consistent with the Department's cautious approach to offshore oil and gas exploration in the Arctic.

II. Findings and Recommendations

Secretary Salazar directed Tommy P. Beaudreau, the Director of the Bureau of Ocean Energy Management (BOEM) and Principal Deputy Assistant Secretary for Lands and Minerals Management at the Department of the Interior (DOI), to lead this review. Key members of the review team included Director James A. Watson of the Bureau of Safety and Environmental Enforcement (BSEE), senior leadership from BOEM and BSEE headquarters and regional staffs, and a technical advisor from the USCG. DOI retained the international consulting firm PricewaterhouseCoopers LLP (PwC) to provide expertise and support in reviewing issues related to safety and operational management systems. The review team received significant participation and contributions from the Federal agencies involved, along with DOI, in overseeing Shell's 2012 activities, including the National Marine Fisheries Services (NMFS), the

[2] "Shell announces pause in Alaska drilling program," Feb. 27, 2013. http://www.shell.us/aboutshell/projects-locations/alaska/events-news/02272013-alaska.html.

National Weather Service (NWS) and others at the National Oceanic and Atmospheric Administration (NOAA); the USCG; EPA; and the U.S. Fish and Wildlife Service (USFWS).

Shell cooperated with this review. Among other things, Shell personnel made presentations to, and were interviewed by, the review team in Washington, DC; Anchorage, Alaska; Seattle and Bellingham, Washington; and Houston, Texas. During these discussions, Shell personnel were forthcoming about their perspectives on the 2012 operations and lessons they have drawn from the experience. Shell also made documents and materials available for the review. The review team also met with personnel from some of the key contractors that Shell retained for work related to its Alaska operations.

The involvement of Alaskans was extremely important to this review. The State of Alaska and its people, including Alaska Natives living on the North Slope, have a direct and strong interest in ensuring that any oil and gas operations and maritime activity offshore Alaska is conducted safely and responsibly. The review team met with representatives from the State of Alaska, including high-level officials in the State's Department of Natural Resources and Department of Environmental Conservation, and members of the Alaska State Legislature. The review team also met with the Mayor of the North Slope Borough, representatives from the Arctic Slope Regional Corporation, and leadership from the Inupiat Community of the Arctic Slope. Senior leaders from DOI, NOAA, USCG and EPA discussed Shell's 2012 operations, and received direct input from the Alaskan Native whaling community, during the Alaska Eskimo Whaling Commission's (AEWC) convention in Barrow in February.

The review also sought information and perspectives from a broad range of other stakeholders and experts. The team met with representatives from the oil and gas and maritime industries working in Alaska, and also received substantial input from a broad range of conservation non-governmental organizations, both in Alaska and in Washington, DC.

This review has identified seven key principles and prerequisites for safe and responsible offshore exploration drilling in the Alaskan Arctic – five applying to industry and two relevant to government oversight. As discussed in detail in this report, in 2012 Shell fell short of successfully addressing all but the last of these principles.

1. **All phases of an offshore Arctic program – including preparations, drilling, maritime and emergency response operations – must be integrated and subject to strong operator management and government oversight.**

Arctic offshore operations are extremely complex, and there are substantial environmental challenges and operational risks throughout every phase of the endeavor, including preparations, mobilization, in-theater drilling operations, emergency response and preparedness, and de-mobilization.

As discussed below, Shell experienced significant problems during phases of the operation that were outside of the core drilling-related competencies devoted to the project, including during the fabrication of critical systems such as the ACS and maritime operations such as the *Kulluk* tow. Thus, although Shell generally performed safely while in-theater conducting drilling operations, and while subject to intense regulatory oversight, it is clear that all phases of an offshore exploration operation in Alaska must be managed and overseen as an integrated endeavor and subject to robust and direct operator management and government oversight.

2. **Arctic offshore operations must be well-planned, fully ready and have clear objectives in advance of the drilling season.**

Because of the inherent geographic, logistical and environmental challenges associated with working on the Arctic OCS, the operating plan and objectives of any offshore Arctic program must be well-planned and designed to provide operational clarity, while also allowing for ample flexibility in light of variable and changing conditions and the need for safe demobilization.

In contrast, Shell entered the 2012 drilling season with substantial uncertainty about the readiness of critical systems such as the ACS and air emission controls, as well as its timelines and operational objectives for the open water drilling window. These uncertainties, and the resulting delays, led to pressure on safety-related deadlines at the end of the season, and contributed to Shell's request to extend, by up to nearly three weeks, the period in which it would be allowed to drill in hydrocarbon-bearing zones beyond the original September 24 cessation date set by BOEM.[3] There should be no loose ends or unnecessary improvisation with critical equipment, assets or drilling plans once operations are scheduled to begin.

3. **Operators must maintain strong, direct management and oversight of their contractors.**

Arctic offshore operations are complex and require operators to bring to bear equipment, systems and personnel with capacity across a broad set of specializations and competencies, some of which must be supplied by contractors. Rigorous and effective operational management is extremely important to establishing sound oversight and internal process management. Moreover, operators must tailor their management and oversight programs to Arctic conditions, and the programs must cover preparations in advance of the drilling season and maritime operations as well in-theater drilling operations.

A recurring theme from Shell's 2012 experience is that there were significant problems with contractors on which Shell relied for critical aspects of its program – including development of the ACS, the air emission mitigation technology applied to the rigs' engines, the condition of the *Noble Discoverer*, and the *Kulluk* towing operation.

4. **Operators must understand and plan for the variability and challenges of Alaskan conditions**.

Reliable weather and ice forecasting play a significant role in ensuring safe operations offshore Alaska, including but not limited to the Arctic. Robust forecasting and tracking technology, information sharing among industry and government, and local experience are

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[3] As discussed below, in response to Shell's request to adjust the end of season deadline, NOAA prepared a sophisticated analysis forecasting probabilities of the freeze-up date in the Chukchi Sea. This analysis did not support the adjustment Shell proposed, and freeze-up ultimately occurred around November 1 as originally projected by BOEM. However, Shell's request to extend the approved period for drilling in hydrocarbon-bearing zones was rendered moot by the failure of the ACS containment dome test (the deployment of which in the Arctic was a prerequisite to entering any hydrocarbon-bearing zones), and BOEM did not act on Shell's request.

essential to managing the substantial challenges and risks that Alaskan conditions pose for all offshore operations.

The weather forecasting and ice management systems Shell employed daily during drilling operations in the Arctic were one of the strengths of its program. As experienced during the *Kulluk* tow incident, however, Alaska's weather changes quickly and produces hurricane-force winds and extremely dangerous sea conditions.

5. Respect for and coordination with local communities.

Alaska Native communities on the North Slope are closely connected to the Arctic Ocean culturally, socially and economically. It is commonly said in Alaska Native communities that "the ocean is our garden," which illustrates the importance of subsistence hunting and fishing, including whaling, to North Slope villages. At the same time, many on the North Slope recognize, and hope to benefit from, the economic and employment opportunities that offshore oil and gas exploration may offer. Accordingly, it is imperative that offshore exploration in the Arctic be harmonized with the needs of North Slope communities, including traditional subsistence use. Moreover, it is an operator's safety and environmental performance that is the ultimate measure of how well and responsibly the company works with North Slope communities and Alaska Natives.

As discussed below, Shell performed well in many aspects of coordinating with Alaska Native and local communities, including abiding by the company's Conflict Avoidance Agreement (CAA) with the AEWC under challenging operational circumstances.

A. Recommended Undertakings by Shell

Based on these findings and as discussed above, the review team has identified two specific undertakings that Shell should complete before the company proceeds with additional offshore exploratory drilling activity in future seasons. First, Shell should develop, and submit to DOI, a comprehensive and integrated operational plan describing in detail its future drilling program. Second, Shell should commission and complete a full third-party audit of its management systems.

B. Government Oversight

This report also defines important principles for government oversight of offshore drilling activity in the Arctic that must be carried forward and further developed. These include, in particular, (1) the importance of continued close coordination among government agencies in the permitting and oversight process, and (2) the need to continue to develop and refine standards and practices that are specific to the unique and challenging conditions associated with offshore oil and gas exploration on the Alaskan OCS.

1. Continued strong coordination across government agencies is essential.

The Federal government – including DOI, NOAA, USCG, EPA and others – engaged in a robust and unprecedented level of interagency coordination, information-sharing and cooperation related to the regulatory approval process and oversight of Shell's 2012 program. This process, which is being applied to Federal oversight of all major Alaskan energy issues through the Alaska Interagency Working Group established by Presidential Executive Order 13580, led to the more efficient and effective reviews of permits and approvals, stronger oversight of Shell's operations, better communication with local communities, greater awareness by Federal agencies of activities potentially impacting their areas of responsibility, and more efficient use of limited Federal resources. Still, the intensity of the regulatory review process and the devotion of substantial assets by DOI, USCG, NOAA and others to oversee Shell's 2012 program caused significant strain on Federal resources, especially in Alaska. Public engagement by Federal agencies, including providing as much transparency and opportunity for public input as reasonably possible, is also important. This is an area of success from the 2012 experience that should be carried forward and improved upon in the future.

2. Industry and government must develop an Arctic-specific model for offshore oil and gas exploration in Alaska.

As Shell's 2012 experience has made absolutely clear, the Arctic OCS presents unique challenges associated with environmental and weather conditions, geographical remoteness, social and cultural considerations, and the absence of fixed infrastructure to support oil and gas activity, including resources necessary to respond in the event of an emergency. Shell's 2012 drilling program was subject to a number of Arctic-specific conditions and standards – including, among others, deployment of subsea containment systems as a prerequisite to drilling into hydrocarbon-bearing zones, limitations on the Chukchi Sea drilling season to provide time for open-water emergency response, a blackout on drilling activity during the subsistence hunts in the Beaufort Sea, and deploying pre-laid boom around vessels during fuel transfers.[4] Shell also undertook additional measures, such as agreeing to transport out drilling muds and cuttings from its Beaufort Sea operation instead of discharging them into the ocean.

Examples include: (1) access to systems with the ability, in the event of a loss of well control, to cap the well and contain hydrocarbons at the source of the discharge; and (2) the availability of a rig, located in the Arctic, that is capable of promptly drilling a relief well. Both of these areas are fundamental to safe and responsible operations in the Arctic, where existing infrastructure is sparse, the geographical and logistical challenges of bringing equipment and resources into the region are daunting, and the time available to mount response operations is limited by changing weather and ice conditions at the end of the season.

Government and industry should continue to evaluate the potential development of additional Arctic-specific standards in the areas of drilling and maritime safety and emergency response equipment and systems. The United States has a leading role among Arctic nations in establishing appropriately high standards for safety, environmental protection and emergency response governing offshore oil and gas exploration in the Arctic Ocean. It is incumbent, therefore, on the United States to lead the way in establishing an operating model and standards tailored specifically to the extreme, unpredictable and rapidly changing conditions that exist in the Arctic even during the open water season.

Finally, DOI should encourage operators working in the Arctic to enter into resource sharing and mutual aid agreements to provide each other with access to operational and

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[4] These Arctic-specific standards applied to Shell's 2012 Beaufort and Chukchi Seas program are discussed throughout the report, including at Section III.C. below.

emergency response resources. The traditional operator-specific, “go it alone” model common with exploration programs in other regions is not appropriate for Arctic offshore operations. A cooperative, consortium-based model offers potential logistical and commercial efficiencies, as well as safety and environmental advantages through the reduction of cumulative operational risks and footprints (including air emissions). Following the *Deepwater Horizon* blowout and spill and after DOI’s establishment of clear guidance requiring subsea containment in support of all deepwater drilling operations, industry pulled together resources, equipment and expertise to establish consortia designed to provide offshore operators with access to critical safety and emergency response equipment, such as capping stacks and other equipment necessary to respond to a subsea blowout. Arguably the need for mutual assistance and resource sharing covering both operational and emergency response assets and resources may be even greater in the Arctic.

III. Background

The oil and gas industry’s interest in the Arctic OCS is driven by the region’s substantial resource potential. BOEM estimates that the Chukchi Sea Planning Area may hold more than 15 billion barrels of technically recoverable oil and nearly 78 trillion cubic feet of technically recoverable natural gas, which is second only to the Central Gulf of Mexico in terms of resource potential offshore the United States. The Beaufort Sea also has significant resource potential – an estimated 8 billion barrels of oil and nearly 28 trillion cubic feet of natural gas.[5]

Other Arctic countries are moving forward with offshore oil and gas exploration in the Arctic Ocean, including Russia, Norway, Canada, Denmark (including Greenland and the Faroe Islands), and Iceland. Proven offshore oil and gas fields have been found along Russia’s vast Arctic shelf in the Barents, Pechora and Kara Seas, although there has been no significant offshore oil and gas production in the Russian Arctic to date. Chevron operates two exploration licenses in the Canadian Beaufort Sea, and in 2012 Chevron undertook an exploratory seismic program there. The Norwegian Arctic is seen as a possible source to replace declining output from mature fields in the North Sea. For example, Norway recently announced that the Norwegian portion of a formerly disputed area with Russia in the Barents Sea could hold an estimated 1.9 billion barrels of oil equivalent, an increase of 15 percent from previous estimates. In 2010, Greenland drew significant attention by awarding seven oil and gas exploration licenses in Baffin Bay, and additional licenses are expected to be awarded off eastern Greenland in 2013.

The United States is at the forefront in evaluating the economic and energy potential of safe and environmentally responsible offshore oil and gas development in the Arctic, as well as the multitude of challenges facing the region, including the consequences of rapid climate change. It is essential that the United States understand the resource potential of the Arctic, and offshore oil and gas exploration has a role in developing that understanding. However, exploration must be conducted cautiously, safely, and responsibly in relation to the sensitive Arctic environment and the Alaska Natives who are closely connected to the Arctic Ocean for subsistence and fundamental aspects of their culture and traditions.

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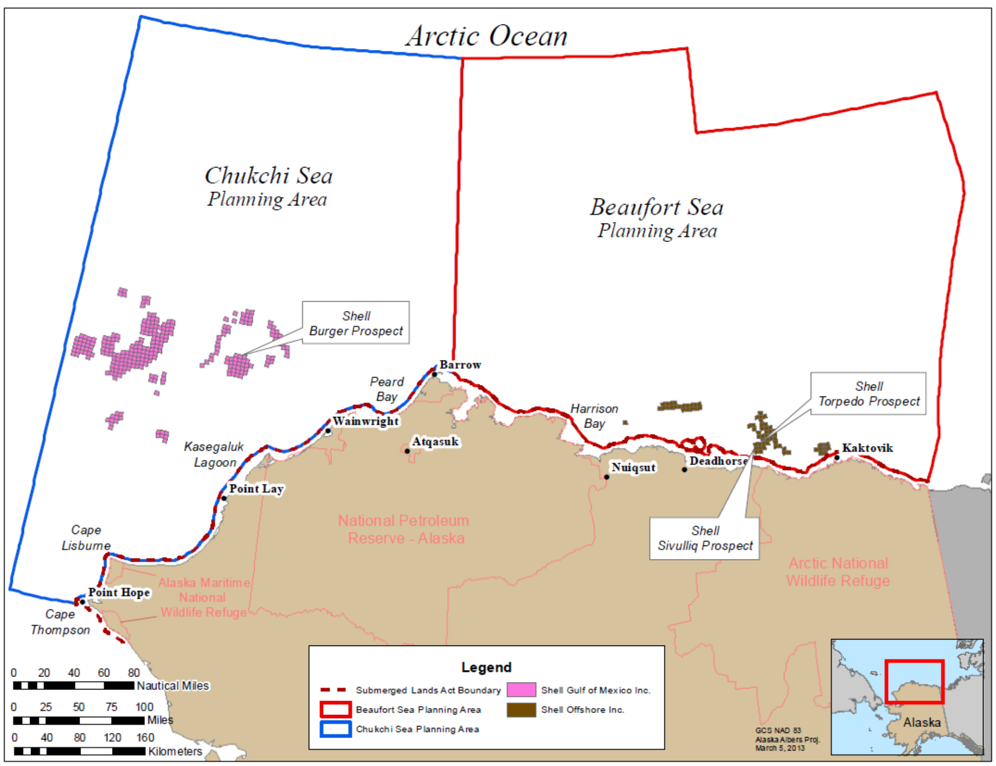
[5] BOEM Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation’s Outer Continental Shelf, 2011.

For example, in July 2011 the President signed Executive Order 13580, establishing the Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska.[6] The working group is chaired by Deputy Secretary of the Interior David J. Hayes, and is designed to promote interagency coordination "for the safe, responsible, and efficient development of oil and natural gas resources in Alaska…while protecting human health and the environment, as well as indigenous populations." The Alaska Interagency Working Group was also closely involved in coordinating Federal regulatory and oversight efforts leading up to the 2012 drilling season. These coordinating efforts embodied at a high level the major, and in many respects unprecedented, focus that the Federal government placed on the review and oversight of Shell's Arctic drilling program, which is discussed further below.

A. History of Leasing and Exploration in the Arctic OCS

Most of the exploration wells in Federal waters in the Beaufort and Chukchi Seas were drilled during the late 1970s through the mid-1980s. Prior to this past summer, only three exploratory wells had been drilled in the Alaska OCS in the past 18 years, the most recent in 2003 near Prudhoe Bay in the Beaufort Sea. Below is a map of Shell's leases in the Beaufort Sea and Chukchi Sea OCS Planning Areas as well as the location of prospects Shell included in its 2012 exploration program.



6 Exec. Order No. 13,580, "Interagency Working Group on Coordination of Domestic Energy Development and Permitting in Alaska," July 12, 2011.

1. The Beaufort Sea OCS Planning Area

The majority of offshore exploration activity in the Arctic OCS has taken place in the Beaufort Sea, primarily near Prudhoe Bay, which has supported oil and gas activity since the late 1960s. Prior to last summer, industry had drilled a total of 30 exploratory wells in Federal waters in the Beaufort Sea, mainly in water depths of approximately 100 feet or less, with Shell drilling or partnering on eleven of those wells. In the 1980s, the Union Oil Company, in partnership with Shell and Amoco, drilled two exploration wells at the Hammerhead prospect, which since has been renamed Sivulliq. Although oil was discovered at Hammerhead, the companies determined that the prospect was uneconomic to develop at that time, and the leases were relinquished in 1998.

Shell currently owns or has an interest in approximately 138 leases in the Beaufort Sea Planning Area. At present, Shell is focused on exploration in the Camden Bay area, which includes its Sivulliq prospect located in the western portion of Camden Bay about 45 miles east of Cross Island, as well as the nearby Torpedo prospect. Shell has conducted multi-year 3D seismic surveys, shallow hazard surveys, and environmental and ecological impact studies in this area in preparation for offshore exploration drilling.

2. The Chukchi Sea OCS Planning Area

BOEM estimates that the Chukchi Sea, which comprises the western side of the United States' Arctic Ocean, holds more undiscovered technically recoverable oil and natural gas than any other OCS planning area except for the Central Gulf of Mexico. Federal waters in the Chukchi Sea have a more limited history of leasing and exploration than the Beaufort Sea. Between 1989 and 1991, Shell drilled four exploration wells in the Chukchi Sea at its Burger, Klondike, Crackerjack, and Popcorn prospects. Chevron drilled a fifth exploration well at the Diamond prospect. All of the wells resulted in the discovery of hydrocarbons, although none was considered commercial for development at the time. All of the leases under which these five exploration wells were drilled have expired.

Chukchi Sea Oil and Gas Lease Sale 193, held in 2008, reflected renewed industry interest in the Arctic OCS and resulted in 487 leases sold for approximately $2.7 billion. Shell alone purchased 275 Chukchi Sea leases for about $2.1 billion. The areas with previous hydrocarbon discoveries remain among the most desirable for further exploration, with Shell's 2012 Chukchi Sea exploration program concentrating on the Burger prospect. Shell acquired all of its current Chukchi Sea leases in Sale 193.

A group of non-governmental environmental organizations and certain North Slope communities challenged the legality of Sale 193. In July 2010, the Federal District Court for Alaska remanded Sale 193 to DOI to address specific deficiencies related to the National Environmental Policy Act (NEPA) analysis conducted in advance of the lease sale. The Court also enjoined activities under the Sale 193 leases, which barred the leaseholders, including Shell, from conducting, among other things, exploration drilling in the Chukchi Sea OCS. In response to the Court's remand, BOEM prepared a Supplemental Environmental Impact Statement (SEIS) addressing the specific deficiencies identified by the Court, as well as providing an updated risk assessment in light of the *Deepwater Horizon* oil spill, and including an additional analysis of the potential impacts of a very large oil spill in the region. Following completion of the SEIS, DOI affirmed Sale 193 in October 2011. The Court lifted the injunction on October 26, 2011, which allowed Shell to proceed with the submission to BOEM of a Chukchi Sea exploration plan.

B. Background Regarding Shell's Arctic Exploration Program

Shell's Chukchi Sea and Beaufort Sea exploration programs evolved over the course of a number of years and in response to changes in regulatory and operational requirements, legal challenges, and lessons learned from the *Deepwater Horizon* oil spill.

1. The Beaufort Sea Program

Shell submitted a Beaufort Sea exploration plan in 2007, which the Minerals Management Service (MMS) approved.[7] The plan was met with legal challenges by environmental organizations, the North Slope Borough, and the AEWC. In May 2009, Shell submitted a revised exploration plan proposing to drill two exploration wells in the Camden Bay area during the 2010 drilling season, which MMS approved in October 2009. Shell never submitted an application for permit to drill (APD) under the 2010 Beaufort Sea exploration plan.[8]

In October 2010, Shell submitted an update to its Beaufort Sea exploration plan that proposed exploration drilling at the Sivulliq prospect during the summer of 2011. In February 2011, Shell withdrew from pursuing exploration drilling in the Beaufort Sea during the 2011 season, citing difficulties in obtaining the requisite air permits. Shell then turned to planning, and working to obtain the necessary approvals, for proposed exploration activity during the 2012 season. In May 2011, Shell submitted a revised Beaufort Sea exploration plan for the 2012 season, and ultimately received conditional approval from BOEM.

2. The Chukchi Sea Program

In May 2009, along with its Beaufort Sea program, Shell submitted an exploration plan proposing drilling in the Chukchi Sea during the 2010 season, which MMS approved in December 2009. This plan proposed drilling up to three wells at three different Chukchi Sea prospects – Burger, Crackerjack, and Shoebill. Shell submitted one preliminary APD for a well in the Chukchi Sea during the 2010 season. However, in the midst of the ongoing response to the *Deepwater Horizon* blowout and oil spill in the Gulf of Mexico, Shell withdrew this APD in early June 2010 and did not move forward with exploration drilling offshore Alaska in 2010.[9]

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[7] MMS was abolished by Secretarial Order in May 2010. The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) replaced MMS from May 2010 through September 2011 while DOI implemented a comprehensive reorganization and strengthening of Federal offshore energy oversight in the wake of the *Deepwater Horizon* oil spill. The reorganization was completed on October 1, 2011 with the establishment of BOEM and BSEE.

[8] As discussed below, Shell submitted, and then withdrew, an APD to drill an exploration well in the Chukchi Sea during the 2010 season.

[9] As discussed in Section IV.A. below, in May 2010, Shell committed to developing and deploying a subsea containment system in support of its Arctic exploration program, based on lessons from the *Deepwater Horizon* incident. On June 24, 2010, Shell requested that DOI issue directed suspensions of its leases in the Beaufort and Chukchi Seas. Later in 2010, the State of Alaska filed a lawsuit in Federal District Court in Alaska claiming that

Although Shell submitted an updated Beaufort Sea exploration plan for the 2011 season, it was unable to propose any exploration drilling in the Chukchi Sea during the summer of 2011 because of the Court-ordered injunction that was imposed in June 2010. As discussed above, the Court lifted its injunction of activity under the Sale 193 leases in October 2011, after which BOEM proceeded with its review of Shell's revised 2012 Chukchi Sea exploration plan for exploration drilling at the Burger prospect.

C. Overview of Federal Regulatory Approvals for the 2012 Season

In order to move forward with its Alaska offshore exploration program in 2012, Shell engaged with agencies across the Federal government to pursue approvals under a host of statutory and regulatory authorities. On March 26, 2012, Shell also signed a CAA with the AEWC designed to manage and mitigate conflicts with North Slope communities' subsistence activity in the Beaufort Sea, where Shell's proposed Camden Bay drilling sites are in close proximity to the bowhead whale migrations. This section briefly describes the various Federal authorities governing offshore oil and gas exploration on the Arctic OCS, and Shell's work to obtain regulatory approvals leading up to the 2012 season. As described above, the Alaska Interagency Working Group promoted an unprecedented level of close communication and coordination across the relevant Federal agencies involved in reviewing, and then overseeing, Shell's 2012 Alaska offshore exploration program.

1. The Exploration Plans

The OCS Lands Act authorizes DOI to grant leases for the exploration, development and production of oil and natural gas on the OCS, which is generally defined as the submerged lands beyond three miles off each coastal state. In order to propose exploration drilling under a lease, an operator must submit an exploration plan to BOEM that describes the proposed activities and their timing, and provides detailed information about, among other things, the drilling rig, the location of each proposed well and the potential onshore and offshore environmental impacts that may occur as a result of the activity proposed under the plan. BOEM conducts a regulatory review of the exploration plan, as well as an environmental review under NEPA, to ensure that the activities meet standards for safe and environmentally responsible operations. As discussed below, the review of Shell's 2012 Chukchi Sea and Beaufort Sea exploration plans resulted in the imposition of a number of Arctic-specific conditions and mitigation measures that governed Shell's drilling operation program.

Shell's Beaufort Sea exploration plan describes drilling up to four exploration wells, beginning in the 2012 drilling season and continuing into subsequent seasons, in the Camden Bay area about 20 miles offshore and in waters approximately 120 feet deep. On August 4, 2011, BOEM approved Shell's revised Camden Bay exploration plan for the Beaufort Sea subject to eleven conditions.[10] These conditions included, among other things, requirements that Shell (1) obtain specific permits and authorizations from BSEE, EPA, NMFS and USFWS; (2)

DOI had imposed a "moratorium" on Arctic offshore drilling, which DOI denied by pointing out, among other things, Shell never submitted any APDs for the Beaufort Sea and withdrew the Chukchi Sea APD. On January 26, 2011, the Court granted summary judgment in DOI's favor and dismissed the State's case.

[10] Approval letter from BOEMRE to Shell, dated Aug. 4, 2011, attached at Tab 1.

confirm the staging and location of a relief well rig; (3) conduct a field exercise demonstrating the company's ability to deploy its capping and containment system; and (4) suspend any exploratory drilling operations in the Beaufort Sea by August 25 and not resume activity until after subsistence whalers from the Alaska Native villages of Nuiqsut and Kaktovik completed their subsistence hunts and Shell received BOEM's approval to resume.[11]

Shell's Chukchi Sea exploration plan proposed drilling up to six exploration wells beginning in the 2012 drilling season and continuing over multiple seasons. The well sites are located about 85 miles northwest of the coastal village of Wainwright, in waters approximately 140 feet deep. On December 16, 2011, BOEM approved Shell's revised Chukchi Sea exploration plan subject to fifteen conditions.[12]

In addition to containing similar conditions as the Camden Bay exploration plan approval with respect to permits and authorizations, successful deployment testing of the capping and containment system and relief well operations, BOEM established Condition 4 governing when Shell would be required to stop drilling in hydrocarbon-bearing zones at the end of the drilling season. Under Condition 4, BOEM required Shell to cease drilling into hydrocarbon-bearing zones within 38 days of a "trigger date" of November 1, established by BOEM based on analysis of historical data from 2007 to 2011 regarding the date of first ice encroachment over the proposed Burger drill site. Condition 4 was designed to provide time for open water emergency response in the event of an incident occurring near the end of the drilling season. Based on the November 1 trigger date, Shell was required to stop drilling in hydrocarbon-bearing zones by September 24. However, BOEM provided for the possibility of adjusting the trigger date – either earlier or later – based on reliable, scientific ice forecasting data capable of predicting with a high degree of certainty when ice would likely encroach on the drill site.[13] While Condition 4 operated to limit the end of the season when Shell would be able to drill into hydrocarbon-bearing zones, Shell would be permitted to conduct other activities, including drilling short of hydrocarbon-bearing zones, up to October 31.

2. Air Permits

The Clean Air Act authorizes EPA to develop and enforce regulations that protect the public from airborne contaminants known to be hazardous to human health. EPA requires operators to obtain permits prior to emitting regulated pollutants at quantities above established thresholds, and each permit typically contains pollution control, monitoring, and reporting requirements. EPA has exercised jurisdiction over OCS sources in the Beaufort and Chukchi Seas since 1990.[14] EPA regulations define an OCS source to include drilling vessels while they

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[11] *Id.*

[12] Approval letter from BOEM, dated Dec. 16, 2011, attached at Tab 2.

[13] *Id.*

[14] In December 2011, Congress transferred authority for air pollution control for the Beaufort Sea OCS and Chukchi Sea OCS from EPA to BOEM. Under an exception for pending or existing permits, EPA retains the responsibility for implementing and enforcing the permits for Shell's exploration operations in the Beaufort and Chukchi Seas, but future regulation of emissions from new oil and gas exploration or production activities in the Beaufort and Chukchi Seas will be the responsibility of BOEM.

are attached to the seafloor, along with other associated support vessels within 25 miles of a drilling vessel that is attached to the seafloor.

The air permit process related to Shell's Alaska exploration drilling program dates back to 2007. For its 2012 Beaufort and Chukchi Sea programs, Shell obtained EPA approval of a revised permit for the *Noble Discoverer* in September 2011, which reduced permitted emissions, primarily through the application of control technologies applied to the rig's engines, of most key air pollutants by more than 50 percent from the levels allowed in earlier permits issued by EPA.[15] These permits were upheld by the Environmental Appeals Board (EAB) in January 2012. EPA approved a draft permit for the *Kulluk* in July 2011, and a modified version of the permit on October 21, 2011, incorporating stricter pollution controls, and reducing key emissions including sulfur dioxide, nitrogen oxides, carbon dioxide, and greenhouse gases. The *Kullu*k permit was appealed to the EAB and upheld on March 30, 2012. Shell obtained final permits for the *Kulluk* and its Beaufort Sea operations on April 12, 2012, and for the *Noble Discoverer* and its Chukchi Sea operations on September 19, 2012.[16]

3. Clean Water Permits

The Clean Water Act prohibits the unauthorized discharge of pollutants from a point source into United States waters.[17] A general National Pollutant Discharge Elimination System (NPDES) permit that covered oil and gas exploration in the entire Arctic region expired on June 26, 2011. Under EPA regulations, an operator may continue under the terms of a previous, expired permit if it submits a timely application to do so in the form of a Notice of Intent (NOI). On December 16, 2010, Shell submitted NOIs covering the proposed drill sites in the Beaufort and Chukchi Seas. On June 23, 2011, EPA authorized Shell to discharge eleven waste streams in the Chukchi Sea and six waste streams in the Beaufort Sea.[18]

In its CAA with the AEWC, Shell also agreed not to discharge into the Beaufort Sea any drilling muds or cuttings. Under this agreement, Shell was required to store and transport away from the *Kulluk* drilling fluids and cuttings, rather than discharge those materials into the ocean as is the common practice in other regions.

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15 Earlier permits were appealed to, and overturned by, the EAB. The EAB is an independent body that is the final decision-maker with respect to administrative appeals of actions taken by EPA, including the issuance of air permits.

16 As described in detail later in this report, Shell ultimately operated the *Discoverer* under an EPA-issued compliance order for the 2012 season.

17 EPA may authorize such discharges by issuing an NPDES permit. For offshore oil and gas activities, EPA typically issues general permits, which EPA describes as "appropriate mechanisms for authorizing discharges from multiple sources that involve the same or substantially similar types of operation." Individual operators may then submit NOIs to discharge pollutants consistent with the terms and conditions established under the general permit.

18 On January 31, 2012, EPA issued new draft general permits for the Beaufort Sea and the Chukchi Sea. These general permits became effective on November 28, 2012.

4. Marine Mammal Authorizations

The Marine Mammal Protection Act (MMPA) prohibits the unauthorized "take" of marine mammals. The term "take" is broadly defined, and includes any "harassment" of marine mammals. Operators whose activities may incidentally (but not intentionally) take marine mammals may apply for an incidental take authorization, which can be in the form of a Letter of Authorization (LOA) or an Incidental Harassment Authorization (IHA). NMFS has jurisdiction over take authorizations for whales and seals, while the USFWS has jurisdiction over walrus and polar bears. Shell received incidental take authorization for its 2012 Beaufort and Chukchi Sea exploration drilling operations from both NMFS and USFWS. Shell's CAA with the AEWC helped the company address the MMPA requirement that applications for incidental take authorizations include either a plan of cooperation or information that identifies what measures will be taken to minimize any adverse effects on the availability of marine mammals for subsistence uses.[19]

5. Oil Spill Response

Pursuant to the Oil Pollution Act of 1990, owners or operators of oil handling, storage, or transportation facilities located offshore are required to submit an oil spill response plan (OSRP) to BSEE for approval. This plan must demonstrate that the owner or operator can respond quickly and effectively if oil is discharged from that facility. The OSRP must also be consistent with the provisions of the National Contingency Plan and with applicable Area Contingency Plans. Under BSEE regulations, companies must review their OSRPs at least once every two years and submit updated plans to BSEE for approval.

In May 2011, Shell submitted to BSEE revisions to its OSRPs for the Beaufort and Chukchi Seas, which had previously been approved in 2009. DOI circulated the revised plans to the agencies within the Alaska Interagency Working Group for review and comment, and also posted the OSRPs on the internet for public review. BSEE, NOAA and other Federal agencies engaged in extensive discussions with Shell regarding the revised OSRPs during the fall of 2011.

BSEE approved Shell's Chukchi Sea OSRP in February 2012, and Shell's Beaufort Sea OSRP one month later. In advance of approving these plans, BSEE – under the auspices of the Alaska Interagency Working Group – received input from other agencies including USCG, EPA, and NOAA. Each plan covers leases owned by Shell in the Chukchi and Beaufort Seas and provides for the mutual use of equipment between both theaters. The approved OSRPs were changed considerably from previous versions of Shell's plans. Specifically, Shell was required to reformat its plans and to demonstrate compliance with specific Federal regulations, include much higher estimates for worst case discharges, develop longer-run trajectories for spills, and provide additional details on the logistics of bringing equipment in from outside the region if necessary. Shell also committed in its OSRPs to deploying the ACS containment system to address the contingency of a well blowout. Shell's adherence with the terms of the OSRPs was verified by a series of tabletop exercises, drills, and equipment inspections.

[19] BOEM's lease stipulations governing activities at Shell's Beaufort Sea and Chukchi Sea drill sites contain similar requirements.

6. Maritime Vessel Requirements

The USCG administers navigation and vessel inspection laws and regulations governing marine safety, security and environmental protection. USCG also is responsible for inspecting the vessels to which those laws and regulations apply. Certain U.S. flag vessels, including the *Arctic Challenger* vessel, must be inspected and receive a Certificate of Inspection (COI). USCG issues a COI only after the vessel passes an inspection confirming that it complies with all applicable statutes and regulations and can be operated safely without endangering life or property.

Foreign flag mobile offshore drilling units (MODUs), including the *Noble Discoverer* and the *Kulluk*, must have a valid Certificate of Compliance (COC) prior to engaging in activities on the OCS. The USCG issues a COC to a MODU after examining the rig and determining it complies with applicable U.S. and international standards. In order for the COC to remain valid, the rig must be maintained and operated in compliance with all applicable marine safety and environmental protection laws and international conventions. USCG and international regulations require self-propelled vessels, such as the *Noble Discoverer*, to have a Safety Management System (SMS) to help ensure safety at sea, prevent the occurrence of human injury or loss of life and avoid environmental and property damage.

7. State and Federal Consultations

The Coastal Zone Management Act (CZMA) encourages coastal states to develop comprehensive programs to manage and balance competing uses of and impacts to coastal resources. However, the Alaska Coastal Management Program (ACMP) expired on July 1, 2011, and has not been reauthorized by the State. As a result, the associated ACMP regulations and all local coastal management plans lost their statutory authority and became unenforceable on July 1, 2011. The expiration of the ACMP removed an important means of formal consultation between the Federal government and the State and local governments concerning OCS matters.

The Endangered Species Act (ESA) prohibits the unauthorized take of species listed as endangered or threatened, and prohibits the destruction or adverse modification of listed species' designated critical habitat. As under the MMPA, "take" is defined quite broadly, and may be authorized by USFWS or NMFS. In addition to imposing restrictions on operators, the ESA also requires Federal agencies to consult with USFWS and NMFS to ensure that authorized actions do not jeopardize the continued existence of endangered or threatened species, or destroy or modify their designated critical habitat. There are a number of endangered, threatened, and candidate species present within the Beaufort and Chukchi Seas. The Federal agencies responsible for authorizing Shell's 2012 exploration drilling activities satisfied their ESA obligations through a series of consultations conducted with NMFS and USFWS and receipt of requisite Biological Opinions and Incidental Take Statements. Shell's adherence to the terms of its MMPA incidental take authorizations also constitute compliance with ESA provisions concerning take.[20]

8. Drilling Permits

Operators must obtain drilling permits from BSEE prior to beginning drilling operations on the OCS. On January 31, 2012, Shell submitted APDs for two wells: the Burger A site in the Chukchi Sea and the Torpedo H site in the Beaufort Sea. On April 17, 2012, Shell submitted eight additional APDs, covering each of the remaining wells under its approved exploration plans. In each case, the initial applications were incomplete, and an iterative process began wherein BSEE would request additional information from Shell, which in turn amended its APDs. BSEE required between four and seven additional submittals from Shell on each APD before the APDs were complete and accurate enough to act upon. In the case of the Burger A well, Shell did not submit a complete APD until August 8, well into the drilling season.

As discussed above, Shell was required, as conditions of the approvals of its exploration plans and OSRPs, to have the ACS containment system fully tested by BSEE and deployed in the Arctic before any drilling into hydrocarbon-bearing zones could occur. Because the deployment test of Shell's ACS system failed, BSEE limited its approval of Shell's APDs to top hole sections. On August 30, BSEE partially approved Shell's Burger A drilling permit to allow Shell to construct a mud-line cellar and set the first two casing strings of the well, but not to drill deep enough to enter potential hydrocarbon-bearing zones. On September 20, BSEE approved a top hole permit for the Sivulliq N site in the Beaufort Sea, and later approved three additional top hole permits that Shell did not proceed with prior to the end of the season.

IV. Evaluation of Shell's 2012 Alaska Offshore Exploration Program

Shell's 2012 offshore drilling operations in the Alaskan Arctic were complex, involving logistical challenges at sea, in the air, and onshore. Shell's two floating rigs, the *Noble Discoverer* and the *Kulluk*, were supported by 20 additional vessels, including icebreakers, supply vessels, tankers, tugs and specialized oil spill response boats, most of which performed multiple missions while in theater. Shell coordinated more than one thousand flights to move personnel to and from the theater and to make protected species and ice observations. This activity required considerable onshore presence and support as well, including the temporary housing of workers in camps and the staging of oil spill response assets.

Shell experienced a number of significant problems when operating outside of its core drilling competencies, and in particular when relying on contractors to deliver critical components or to conduct certain operations. These shortcomings offer important lessons for Shell and other operators, as well as for government regulators, regarding the challenges associated with conducting safe and effective offshore exploration operations in the Arctic.

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[20] USFWS issued its Revised Biological Opinion and Conference Opinion for Oil and Gas Activities in the Beaufort and Chukchi Sea Planning Areas on May 8, 2012. NMFS issued ESA Incidental Take Statements to Shell on June 4, 2012 and to BOEM on June 11, 2012.

When conducting operations within its core competencies during the open-water drilling season, and while subject to daily oversight, Shell generally performed safely. Shell was able to drill top hole sections in both the Chukchi and Beaufort Sea theaters with no spills, no significant injuries to workers and virtually no reported impacts on subsistence activities. With the significant exception of air permit violations, one minor safety-related incident of non-compliance on the *Noble Discoverer* that was promptly addressed, and other relatively minor issues discussed below, Shell's operations in the Beaufort and Chukchi Seas generally complied with applicable regulations and the conditions of its plans and permits.

A. The Arctic Containment System

In May 2010, while efforts to control the Macondo well blowout in the Gulf of Mexico were still ongoing, Shell submitted to DOI a list of safety measures that Shell pledged to incorporate into its Arctic drilling program, based on lessons Shell stated it had already learned from the *Deepwater Horizon* incident.[21] Among those measures was Shell's commitment to deploy a pre-positioned, "pre-fabricated coffer dam" to collect hydrocarbons in the event of a subsea blowout. In late September 2010, during a hearing of the National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, Shell's Alaska Vice President presented a slide showing a "proposed sub-sea containment system," which consisted of a subsea containment dome that could be placed over a hydrocarbon leak at the seafloor and a hose leading from that dome to a surface support vessel that would collect, process, flare, and store the hydrocarbons as needed. These commitments related to subsea containment were subsequently formalized in Shell's exploration plans and OSRPs, and were a key basis for DOI's approval of those plans.

Shell's commitment in the summer of 2010 to deploy a subsea containment system to support its Arctic operations led to the development of the ACS. The ACS is a containment system designed to capture oil and gas from a capping stack or from a containment dome with a capacity of at least 25,000 barrels per day. The primary components of the ACS are (1) a staging and processing system mounted on a floated barge, the *Arctic Challenger*; (2) high pressure hoses designed to connect to a capping stack; and (3) a containment dome and associated connecting hoses. The containment dome itself is designed to contain and separate hydrocarbons from water through discrete flows of oil and gas to the processing facilities while returning most of the separated water through the bottom of the dome. The ACS represents a last line of defense to a serious loss of well control incident. Initial defenses include: (1) the injection of kill-weight drilling muds into the well, (2) activation of the blowout preventer, and (3) deployment of a capping stack to shut in the well. If these measures fail, the ACS containment dome is designed to capture flows from the well and facilitate their separation and storage.

Shell contracted with Superior Energy Services (Superior) to design, fabricate, own and operate the ACS. Shell informed the review team that the company selected Superior to design and build the ACS based on the extensive experience of two of Superior's subsidiaries, Wild Well Control and Marine Technical Services, with well control and containment dome system deployments in the Gulf of Mexico. Even though Shell committed to building and deploying a subsea containment system in support of its Arctic operations in mid-2010, work on designing

[21] Letter from Marvin Odum to S. Elizabeth Birnbaum, dated May 14, 2010, attached at Tab 3.

and fabricating the ACS, including the retrofitting of the *Arctic Challenger*, did not begin until late 2011, less than nine months before Shell intended to begin the 2012 drilling season.

1. The *Arctic Challenger*

In April 2011, after consulting with Shell about potential surface support vessels for the ACS, Superior selected the *Arctic Challenger*, an ice class barge built in 1976. The *Arctic Challenger* had been used to supply North Slope oil fields until 2001, but was inactive for about ten years. In preparation for the 2012 drilling season, the *Arctic Challenger* entered a Portland, Oregon shipyard in November 2011 to begin undergoing inspections, structural modifications and repairs. It was not until late March 2012 – only four months before the planned start of the Arctic drilling season – that the *Arctic Challenger* was moved to Bellingham, Washington for the beginning of construction of the facilities that would allow the barge to perform as the surface support vessel of the ACS.

Before it could operate, the *Arctic Challenger* needed to be classed by the American Bureau of Shipping (ABS) and certified by the USCG.[22] Shell, Superior, and ABS met with the USCG in August 2011 to initiate discussions regarding the requirements for classification and certification, and the USCG accepted Shell's proposed standards for classification and certification of the vessel in December.

Shell was not actively involved in overseeing Superior's progress, and in developing solutions to emerging problems, during most of the refurbishment and classification process for the *Arctic Challenger*. Indeed, Shell personnel described Superior's work on the ACS during late 2011 and the first half of 2012 as a "black box." Moreover, Shell did not have naval or marine engineering expertise to advise on the *Arctic Challenger* refurbishment and to identify and troubleshoot problems alongside Superior. Shell has acknowledged these weaknesses in its oversight of the ACS development.

On May 10, 2012, ABS informed Superior that there were significant technical issues that led ABS to believe that "the project will not be able to attain the required design approval in a time frame suitable to your needs."[23] On May 31, ABS notified Superior about "serious concerns" regarding engineering calculations intended to demonstrate that the vessel would be able to operate in Arctic wind and sea states.[24]

It was not until June 2012 that Shell engaged directly and at a high level on the problems with the *Arctic Challenger* classification and certification process. From June through September 2012, there were frequent meetings between Shell, USCG, BSEE, ABS, and Superior to resolve a litany of technical issues related to classification and USCG certification, most of which were safety related. It was at this time that Shell poured tremendous manpower resources into the *Arctic Challenger* project. Shell man-hours devoted to the ACS project leapt from fewer

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[22] A vessel classed by ABS is designed, constructed and periodically surveyed to verify compliance with ABS technical standards and mitigate safety and environmental risks.

[23] Letter from ABS to Superior Energy Services, dated May 10, 2012.

[24] Letter from ABS to Superior Energy Services, dated May 31, 2012.

than 2,000 in May 2012 to approximately 7,000 in July. Despite Shell's increased direct management, devotion of substantial personnel and financial resources, and focused attention on rapidly resolving outstanding issues during the summer of 2012, it did not obtain classification and certification of the *Arctic Challenger* until October 2012, missing the entire 2012 drilling season.

A number of factors contributed to Shell's inability to bring the *Arctic Challenger* on line in time for the 2012 drilling season, including: (1) the selection of a vessel in need of significant retrofitting; (2) the late start of design and construction operations, all contributing to unrealizable timelines for construction, testing, and obtaining Federal approvals; (3) insufficient engagement by Shell management and technical personnel; and (4) turnover of certain Superior personnel working on the retrofitting project.

2. The Containment Dome

The other major component of the ACS is the containment dome, which Superior designed with new technology intended to minimize water collection and hydrate formation while deployed over a leak. The development of the dome suffered from similar delays to those associated with the *Arctic Challenger*, which resulted in repeated postponements of the BSEE-required dome deployment test. Again, there were significant communication problems between Shell and Superior. For example, during the containment dome testing process, Superior acknowledged that it did not completely understand the details of how the dome would need to be deployed in the Arctic, particularly in the water depths in which Shell would be drilling.

The government's inspection of the containment system involved two steps. First, on August 26 and 27, BSEE engineers confirmed that the surface treatment and storage components on the *Arctic Challenger* could process a flow equal to twice the expected worst case discharge rate. The second test involved the deployment of the dome. The dome deployment test began on board the *Arctic Challenger* in Puget Sound on September 11, 2012, while work on the vessel to obtain USCG certification was still ongoing. During the inspection, BSEE staff observed the absence of clear lines of authority on the vessel, and the operation was beset by problems such as the tangling of a remotely-operated vehicle in the dome's rigging, a loose connection on one of the winches, and a serious miscalculation of the amount of weight attached to the dome to keep it submerged.

Shortly after midnight on September 15, the containment dome, which had been positioned at a depth of more than 100 feet, rose rapidly through the water and breached the surface. A few minutes later, the tanks providing buoyancy to the dome vented, and the dome quickly plunged. It sank too rapidly to allow for pressure equalization, and the upper chambers of the dome were crushed. Shell and Superior investigated the causes of the dome's failure, which led to significant changes to the dome's design and construction, including adding buoyancy, installing a protective frame, stiffening of the tank, and installation of larger equalization vents. Because of the failure of the containment dome deployment test, Shell could not obtain permits to drill into potential hydrocarbon-bearing zones, meaning the dome deployment test failure was decisive in limiting Shell from making a potential discovery during the 2012 drilling season.

Finally, Shell's failure to develop a functional ACS in advance of the 2012 drilling season also prevented the company from conducting live training of the crews that would man and operate the *Arctic Challenger* in the event of a loss of well control. Instead, Superior conducted crew training at its newly-built simulation center in Anchorage. While this simulation center is impressive in many respects, preparations for Arctic operations should include the opportunity for crews to participate in live exercises aboard the same vessels they would be expected to man and operate under emergency conditions.

B. Rig Preparations and Fleet Mobilization

There is no consensus with respect to whether floating drilling rigs or jack-up rigs provide the optimal configuration for Arctic exploration operations, and there are advantages and disadvantages associated with each. The ability to disconnect from the well quickly when ice is approaching is considered to be one of the strengths of a floating rig configuration, although operating a floating rig in shallow water depths and rough Arctic seas requires a rigid mooring system to ensure that the rig remains centered over the well. The *Noble Discoverer* has a "turret mooring" system, which allows the vessel to "weathervane" or rotate into the wind or waves without needing to disconnect from the well. However, this procedure requires frequent engine activity, which contributes to air emissions from the operation.

In planning its Arctic exploration program, Shell chose to refurbish existing floating drilling rigs. The *Kulluk* is a conical drilling unit that was purpose-built in 1983 to drill in ice conditions, and drilled approximately a dozen wells in the United States and Canadian Beaufort Sea between 1983 and 1993. Shell purchased the *Kulluk* in 2006, and then retained Frontier Drilling to refurbish, staff, and operate the rig. Noble Drilling purchased Frontier in 2010 and took over operation of the *Kulluk*. The *Noble Discoverer* was originally built for a non-drilling purpose in the mid-1960s and then was converted to a drillship in the mid-1970s. Shell refurbished the *Noble Discover* by, among other things, winterizing the vessel and reinforcing the hull for ice.

Both the *Kulluk* and *Noble Discoverer* were refurbished at the Vigor Marine Shipyard in Seattle. The initial USCG examination of the *Noble Discoverer* on June 6, 2012 identified 23 deficiencies. The deficiencies were addressed by June 20, at which point USCG issued a COC for the *Noble Discoverer*. The initial USCG examination of the *Kulluk* took place on June 15 and found 19 deficiencies. Those deficiencies were addressed, and a COC for the *Kulluk* was issued on June 24. On June 27, the *Noble Discoverer* and *Kulluk* departed Seattle for Dutch Harbor, Alaska, and arrived on July 7 and July 15, respectively.

On July 14, the *Noble Discoverer* dragged its anchor in Dutch Harbor, drifted nearly 700 yards, and came within 100 yards of grounding. Shell stated that its investigation found that the drifting stemmed from Noble's use of only the minimum amount of anchor chain and the absence of contingency plans to sufficiently address weather conditions. Shell reported that it took a number of actions as a result of the anchor drag, including reviewing and updating company guidance for anchoring a ship in certain configurations, and reviewing the management system on board the *Noble Discoverer*.[25] The vessel was undamaged in the incident, and on August 25 it left Dutch Harbor for the Chukchi Sea.[26]

In addition to the two drilling vessels, Shell assembled a fleet of 20 support vessels for the operation. Three vessels were built specifically to support Shell's operations: the *Nanuq* oil spill response vessel, the *Aiviq* anchor handler, and the *Sisuaq* offshore supply vessel. Another eight were upgraded by Shell. Nearly all of the support vessels served multiple functions. For example, the *Nanuq* was primarily designed as an oil spill response vessel, but it also assisted with ice management, conducted scientific data gathering, handled anchors, and served as crew quarters, among other functions.

C. Shell's Drilling Operations in the Beaufort and Chukchi Seas

1. Operational Logistics

To prepare for and conduct operations in the Arctic last year, Shell employed and managed a complex set of vessel, equipment, and personnel movements. Shell's vessels traveled a total of approximately 240,000 nautical miles, conducted 23 ice reconnaissance missions, participated in 500 vessel-to-vessel personnel movements, and transferred 3.25 million gallons of fuel in 23 operations with no reported pollution. Shell pre-laid boom during all fuel transfers, as required by the terms of its leases, an Arctic-specific standard that is not required elsewhere on the U.S. OCS.

The complexity of Shell's marine and drilling operations in theater was increased further by air permit emissions limitations. These restrictions limited the number of support vessels that could come within 25 miles of the drilling rigs at any one time. Shell's efforts to comply with the air permits included the use of individual vessels for multiple missions. In order to manage in-theater logistics under the terms of the air permits, Shell developed an internal vessel tracking and planning system after the season already was underway. Although the tracking system appears to have worked, this is an example of a critical system that was not established in advance of the drilling season. Shell informed the review team that it intends to refine and improve this system for use in future operations.

Shell coordinated nearly 12,000 passenger trips on flights to and from the North Slope, with over 650 personnel stationed offshore at any given time. When combined with flights to conduct required protected species monitoring and ice observations, there were a total of 562 helicopter flights and 535 fixed wing flights during the 2012 operation. Terms in the CAA required flights to be routed to minimize impacts on marine mammals, and Shell coordinated with subsistence hunters daily to obtain rerouting information intended to minimize this conflict.

Although largely successful and virtually free of incident, Shell did experience challenges with its in-theater logistical operations, particularly in the area of aviation. BSEE inspectors reported that on multiple occasions that Shell's helicopter contractor did not enforce survival suit requirements for trips offshore. In addition, the helicopters lacked deicing equipment and,

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25 Shell has not yet provided DOI with documentation related to this management review of the *Noble Discoverer*.

26 The *Kulluk* departed Dutch Harbor for the Beaufort Sea on August 20.

significantly, were unable to fly under Instrument Flight Rules (IFR), creating operational constraints on personnel movement and potential safety issues. The IFR problems might have been resolved if Shell had engaged the FAA earlier in discussions with its aviation contractors. Early engagement with the FAA might also have benefited airspace awareness and coordination efforts.

The first Shell vessel to transit north of the Bering Strait in 2012 was the icebreaker *Nordica* on July 22. Next were the anchor handlers *Tor Viking* and *Aiviq*, which pre-laid anchors for the *Noble Discoverer* at the Burger A drill site in the Chukchi Sea from August 8 through 10. Each anchor was laid several hundred meters further than described in the pattern approved by BOEM in Shell's Revised Chukchi Sea exploration plan. Although the anchor pattern deviated from the exploration plan, BOEM had analyzed the environmental and geohazard impacts of a larger anchor pattern footprint than provided in exploration plan. Although BOEM admonished Shell for the deviation, the larger pattern did not present any potential environmental impacts that had not been considered by BOEM.

2. Timing of Drilling Operations

Shell originally planned to begin drilling operations as early as the second week of July 2012. Shell initially attributed delays to the start of its drilling program to persistent ice in the Chukchi Sea. However, the most significant reason for delays in Shell's drilling operations was the company's inability to complete and deploy the ACS.

On August 30, BSEE approved a limited drilling permit for Shell, which authorized Shell to drill a top hole at the Burger A well site, consisting of a mudline cellar and the first two casing strings down to approximately 1,400 feet.[27] This depth was considerably shallower than the expected liquid hydrocarbon-bearing zones, based on geological and geophysical data for the area. On September 9, Shell began the first exploratory drilling operations in the Chukchi Sea in over two decades. Approximately twelve hours after the start, however, Shell stopped drilling and prepared to move off location due to an unusually large piece of multi-year ice that it had observed moving towards the Burger A site in the Chukchi Sea. At a point when the ice was still approximately three days away from the Burger site, the crew of the *Noble Discoverer* initiated their disconnect procedures and successfully moved off the well.

This sequence of events involving an encroaching ice floe at the Burger site is an example of Shell implementing its Ice Management Plan (IMP).[28] Shell successfully followed its operational protocols with respect to sea ice incursion and other environmental conditions included in its exploration plans, consistent with BOEM's regulatory requirements for operators

[27] A mudline cellar is a large hole dug into the seafloor that is intended to house the blowout preventer in order to protect it from passing ice.

[28] Shell's IMP is part of its Critical Operations and Curtailment Plan (COCP), and is designed to "[facilitate] appropriate decision-making and responses to the threat of hazardous ice[,] and procedures set forth in the IMP prevent damage or harm to personnel, assets, or the environment." The IMP defines five ice alert levels, and establishes roles, responsibilities, and actions for different components of Shell's operations for each alert level. In general, the COCP establishes thresholds and protocols for ceasing operations in response to developing hazards, such as encroaching ice.

proposing to conduct exploration drilling activities offshore Alaska.[29] Shell identified potential hazards through its Ice and Weather Advisory Center, an integrated ice forecasting service that incorporates ice and weather forecasting data from the NWS, climate studies, NOAA and Canadian ice services, and advanced satellite imagery to develop daily ice forecasts. While in theater, Shell also effectively employed meteorologists with Arctic forecasting experience to help produce snapshots of current conditions and forecasts of weather conditions into the future.

Shell returned to the Burger A drill site approximately two weeks later, after the ice floe passed. While the Burger ice flow episode provides an example of Shell successfully managing ice conditions and responding appropriately to a potential hazard, it also highlights the inherently unpredictable nature of working in the Arctic. Shell's already-delayed Chukchi operations lost additional time, pointing out the need for ample "float" time in Arctic drilling schedules and objectives. Ultimately, drilling the Burger A top hole took Shell nearly a month longer than the company originally had estimated.

Shell continued its drilling operations at the Burger A site for the remainder of the season without any injuries, spills, or significant safety violations. BSEE inspectors, who were present on the rig throughout the drilling operation, reported one minor violation, for a temporarily removed walkway, that was quickly remedied.

In the Beaufort Sea theater, BSEE issued a top hole drilling permit to Shell for the Sivulliq N site on September 20. However, because Shell was required by the terms of the CAA and BOEM's conditional approval the exploration plan to wait until the end of the subsistence whale hunt before beginning operations, Shell was not able to start drilling operations in the Beaufort Sea until October 3. As in the Chukchi Sea, the drilling operations were conducted without injuries, spills, or significant safety violations. However, also as with the Chukchi Sea operations, the Sivulliq well took much more time than Shell originally projected. In particular, Shell experienced complications in constructing the mudline cellar for the Sivulliq well. Shell reported that it constructed the mudline cellars extremely cautiously due to a lack of backup equipment and a crew that was inexperienced with the use of a mudline cellar bit, because mudline cellars generally are not used outside of the Arctic OCS. Shell also encountered unexpected boulders during drilling at the Sivulliq site, which delayed completion of the mudline cellar. Ultimately, Shell was only able to set one casing string at Sivulliq, rather than the two casing strings that BSEE permitted, before the drilling season ended.

In submissions to DOI, Shell consistently underestimated the length of time required to complete each step of its drilling operations. The timelines provided by Shell proved to be unrealistic and did not account for complications and delays that should be budgeted for when operating in the Arctic. While Shell's internal expectations might have been more modest than the estimates it provided DOI, a better practice would be to have clear communication between the operator and regulator about objectives, schedule, and variables, including anticipating float time in drilling schedules due to variability of Arctic conditions.

[29] BOEM regulations establish special requirements for operators proposing to conduct exploration drilling activities offshore Alaska that include the submission of "emergency plans" as well as critical operations and curtailment procedures. Among other things, operators must identify "ice conditions, weather, and other constraints under which the exploration activities will either be curtailed or not proceed."

3. Conflict Avoidance and Coordination with Local Communities

To minimize any cultural or resource impacts to subsistence whaling activities from Shell exploration operations, and to satisfy requirements imposed by MMPA incidental take regulations and applicable BOEM lease stipulations, Shell took a number of important steps to work with the AEWC and North Slope communities.

Beginning in January 2009, Shell held numerous public meetings with North Slope communities and organizations to inform community leaders about proposed operations and to obtain input on potential environmental, social, and health impacts, as well as proposed mitigation and conflict avoidance measures. As an outgrowth of these meetings, Shell developed a Communication Plan with local communities to coordinate with local subsistence users, such as village whaling captains, to minimize the risk of interfering with subsistence hunting. As part of this plan, Shell set up Communications Centers (Com Centers) in coastal villages along the Chukchi and Beaufort Seas, which were manned during exploration activities. Shell also employed local subsistence advisors from these villages to provide consultation and guidance regarding whale migration and subsistence activities. The subsistence advisors' responsibilities included reporting subsistence-related comments, concerns, information, coordinating with Com Center personnel, and advising Shell how to avoid conflicts with subsistence hunting activities.

In the Beaufort Sea, Shell also worked under its CAA with the AEWC. Under the CAA, as well as a condition of BOEM's approval of the Camden Bay exploration plan, Shell was required to suspend all operations in the Beaufort Sea beginning on August 25 for the Nuiqsut and Kaktovik subsistence bowhead whale hunt, resuming drilling operations only after the hunt concluded. This whaling deferral period was designed to avoid a potential source of conflict between Shell and local subsistence users by establishing a schedule for different uses of overlapping offshore areas. The CAA also included a range of other terms – some of which demonstrate best practices for operating in the Arctic. For example, Shell agreed to "zero discharge" into the water of drilling muds and cuttings.

The relationship between Shell and the AEWC, and the terms of their CAA, helped to facilitate ongoing coordination and avoid potential conflicts over the course of the season. On September 24, 2012, Shell requested approval to move the *Kulluk* drill rig onto the drill site at Sivulliq, but not to commence drilling operations. At that time, the village of Nuiqsut had completed its hunt, but Kaktovik had one strike remaining, with their hunt having been unexpectedly delayed by the funeral of a whaling captain. The AEWC supported Shell's request, and on September 25 BOEM granted its approval of the rig move, but stressed that Shell was not allowed to commence exploration drilling operations without receiving specific approval from BOEM following the completion of the Kaktovik bowhead whale subsistence hunt. The AEWC agreed to allow Shell to commence drilling by October 9 regardless of whether Kaktovik had completed whaling. Ultimately, Kaktovik successfully completed its hunt on October 3, allowing Shell to commence drilling operations, with BOEM approval, later that day.

4. Federal Oversight During the Drilling Season

The Federal government also mobilized considerable resources to the North Slope and Arctic OCS during the 2012 open water season. Although the USCG's closest base to the Arctic is in Kodiak, Alaska, approximately 940 miles south of Barrow, the USCG has in recent years increased its presence above the Arctic Circle during the summer and early fall. In 2012, as part of Operation Arctic Shield 2012, the USCG deployed substantial assets to the region, including multiple cutters, two ice-capable buoy tenders, two MH-60 helicopters stationed in Barrow, plus air, ground, and communications crews. Operation Arctic Shield also features significant community outreach and capability assessment components.

USCG helicopters and personnel were used in late September to conduct joint BSEE-USCG unannounced inspections of oil spill response (OSR) assets stationed in Prudhoe Bay, Wainwright, and offshore in the Beaufort Sea. These field inspections were the last in a series of OSRP verification activities held throughout 2012, including table-top exercises in March, May, and September, and a May field inspection by BSEE of OSR equipment, deployment exercises, and training activities. Some intended inspections and deployments could not be conducted on the North Slope in September due to the Beaufort Sea whaling season and weather conditions. However, the tabletop exercises and inspections demonstrated that Shell was in compliance with its OSRPs.

To ensure that Shell was conducting drilling operations in a safe and environmentally protective manner, BSEE had an inspector on board each rig full-time from the start of drilling operations to the end, an Arctic-specific practice on the OCS. The inspectors were invited to all meetings on the rigs, and were responsible for monitoring compliance with all drilling regulations, as well as lease stipulations and EP approval conditions addressing operational requirements. These inspectors, like all BSEE inspectors, had the authority to shut down operations if they found serious violations. BSEE issued one incident of non-compliance to Shell for the *Noble Discoverer* crew's failure to replace a section of walkway that had been removed to facilitate the movement of the mudline cellar bit. Shell immediately corrected the conditions that led to the issuance of the violation. The inspectors reported that the operations were being conducted cautiously, and in compliance with the regulations under their purview. The constant presence of BSEE inspectors added an additional oversight element directed towards ensuring compliance with environmental standards and monitoring requirements.

5. Compliance with Air Permits

Before the start of the season's activities, Shell began to anticipate challenges complying with the terms of its EPA air permits, as testing showed that emission levels provided by Shell's contractor, D.E.C. Marine, and incorporated into the terms of the permits were unrealistic. Shell's most significant problems were the six main generators on the *Noble Discoverer*.[30] By June 28, 2012**,** Shell submitted a revised permit application for the *Noble Discoverer*. Among other issues, the application detailed problems with the D.E.C. Marine SCR emission control equipment, which had not performed in testing at the levels specified by D.E.C. Marine and included in the permit. Only once in more than 60 tests had the equipment met the NOx limit, and even then not under conditions approximating those in which the engines would be functioning in the Arctic. Moreover, equipment testing revealed structural deficiencies, such as

[30] Testing demonstrated that achievable emissions rates for NOx were inconsistent with technical specifications provided to Shell by D.E.C. Marine. Shell began working with a different manufacturer, Caterpillar, and identified the need to increase specifications for the *Discoverer's* release of particulate matter and for emissions from the proposed oil spill response vessel.

problems with the catalyst breaking down.[31] Shell belatedly switched contractors to Caterpillar CleanAIR Systems, a company that it believed had the significant international experience and relevant technical expertise to be beneficial for the "remoteness of the Arctic."[32]

In light of the need for the revised permit to undergo public comment prior to finalization, EPA issued a Compliance Order on September 7, 2012, for the purpose of supporting 2012 operations. The compliance order was based on Shell's June 2012 application to revise the permit for future years. The compliance order imposed temporary limits for some emission sources higher than in Shell's permit, but EPA expected the fleet's overall emissions for 2012 to be lower than the original permit allowed due to Shell's shortened operating season. Shell also identified the need for minor revisions to the *Kulluk* permit.

Over the course of the season, Shell's equipment was unable to perform at the revised levels specified in the compliance order and permit revision applications. EPA issued two separate Notices of Violation to Shell, citing multiple permit violations for both the *Kulluk* and *Noble Discoverer* and associated fleets that operated in the Chukchi and Beaufort Seas in 2012. The violations were based on EPA's inspection of the *Noble Discoverer* and Shell's self-reports of excess NOx emissions for the *Noble Discoverer* and the *Kulluk*. EPA also terminated the September 2012 Compliance Order for the *Noble Discoverer's* permit. Issuing a Notice of Violation is a common first step once EPA has identified permit violations,[33] and this action does not preclude Shell from applying for future permits. Shell has once again revised its permit application for the *Discoverer*, and a revised permit is expected to be available for public comment in early 2013.

In addition to reflecting the need for improved communication with and oversight of contractors and manufacturers, Shell's air permit challenges underscore the need to better understand the performance of different technologies in the Arctic. Much of Shell's emissions control equipment was untested in Arctic conditions, and Shell and its manufacturers learned that some equipment did not perform as expected in those circumstances – for example, cold temperatures may have limited Shell's ability to bring its incinerator up to a specified temperature prior to burning waste, leading to a less complete combustion and, thus, a greater amount of pollution. All told, Shell's efforts over the years to work with EPA to revise the permits, improve technological controls, and develop more realistic projections have generated significant lessons about the ways in which key equipment may function differently in Arctic environments.

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31 See page 5: http://www.epa.gov/region10/pdf/permits/ocs/shell/Shell_application_to_revise_Discoverer_Chukchi_air_permit_June_28_2012.pdf

32 *Id.*

33 Next steps can include a consent decree for penalties, orders to correct the violations, and possible mitigation measures. Consent decrees are subject to public notice and comment.

6. Environmental Monitoring and Collection of Scientific Data

Shell was required to undertake extensive environmental monitoring efforts in order to comply with a broad range of environmental protection requirements – for example, the terms of EPA Clean Air Act and Clean Water Act permits, as well as NOAA's marine mammal take authorizations. In addition to collecting data through environmental monitoring measures like those noted above, Shell undertook additional efforts to understand the physical environment and ecosystems at its drill sites.[34] During the three years leading up to the 2012 drilling season, Shell dispatched teams of physical and biological oceanographers to conduct sampling at each of its drill sites to provide an understanding of pre-existing conditions and inter-annual variability. During the drilling season, Shell monitored the following:

- Meteorological and physical oceanographic conditions, including surface wind direction and speed, ambient air temperature, current speed and direction in the water column, and water temperature and salinity through the water column;
- Water chemistry and characteristics, including an assessment of metals and organics, turbidity, and oxygen content through the water column; and
- Biological sampling and observations, including an assessment of benthos, epibenthos, zooplankton and phytoplankton, and fishes, as well as characterization of the communities of these organisms and sampling of biota.

Information derived from these efforts is expected to further the understanding of the local environment and help inform future decision-making.

D. Demobilization and Post-Drilling Season Problems with Both Rigs

Many of the most significant lessons to be learned from Shell's experience in 2012 are from the end of the drilling season and the demobilization of the program. Due to a number of factors – including Shell's lack of preparation with respect to the ACS system, delays associated with the unpredictability of Arctic ice and weather conditions, and circumstances that extended the drilling blackout during subsistence hunting in the Beaufort Sea into early October – Shell got a very late start on its drilling program in both the Chukchi and Beaufort Seas. The late start, and continuing uncertainty about whether Shell would be able to deploy the ACS, put significant internal pressure on Shell to make as much progress as possible with its drilling program at the end of the season, which is not an optimal operating posture. Moreover, Shell experienced problems with its demobilization at the end of the year, including most significantly the lost tow and grounding of the *Kulluk* during a winter storm in rough Alaskan seas in late December.

1. Ice Forecasting at the End of the Season

As discussed above, Condition 4 of BOEM's approval of Shell's Chukchi Sea exploration plan required that Shell cease drilling into hydrocarbon-bearing zones 38 days from

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[34] This work is noted in Section 10.0 of Shell's Beaufort EP and Section 10.0 of Shell's Chukchi EP.

an established “trigger date” of November 1, which was set based on an analysis of the date of earliest ice excursion over the Burger drill site, using satellite imagery from 2007 through 2011. The purpose of Condition 4 was to provide time for open water response in the event of an end of season incident or spill. Condition 4 specifically provided that adjustment to the trigger date, from which the 38-day open-water period is calculated, be based on convincing scientific information predicting with a high degree of certainty that ice encroachment over the well site was likely to actually happen in 2012 at a date different than November 1.

On August 21, 2012, Shell submitted a request to BOEM to adjust the trigger date based on a forecasting approach that relied on reference to an “analog year” with similar overall weather patterns. Shell argued that 2006 was an appropriate analog year and forecasted freeze-up at the Burger site would occur sometime between November 12 and 18, which would constitute a two to three week adjustment to the trigger date.[35] In response to Shell’s request, BOEM and NOAA, including NOAA’s NWS and National Ice Center (NIC), engaged in an intensive review of Shell’s request and forecasting methodology. NOAA developed a sophisticated forecasting analysis of ice conditions at the end of the 2012 season, which projected a 1 in 3 chance of freeze-up at the site by October 28; a 50-50 chance of freeze-up in the November 8 to 12 timeframe; and a 7 in 10 chance freeze-up by November 22. Ultimately, freeze-up occurred on approximately November 1. In light of the failure of the ACS containment dome test on September 15, BOEM did not respond to Shell’s request to adjust the trigger date. Because Shell could not drill into hydrocarbons without deploying the ACS, the question of calculating the date on which Shell was required to stop drilling into hydrocarbon-bearing zones was moot.

The close working relationship between BOEM, NWS and NIC on weather monitoring issues is a significant success coming out of the 2012 exploration season, and the relationship should be continued. In light of the importance of robust ice forecasting capability, as evidenced this past summer, BOEM and NWS are working towards initiating a joint study in Fiscal Year 2013 that aims to further improve the resolution and interpretation of available data about ice formation, including new ice as well as pack ice incursion timing, growth, distribution, density, and velocity. The agencies are focused on both beginning and end-of-season ice predictions, as well as the reliability of forecasting storm events both in and around the Arctic operating theater.

2. Demobilization

By October 26, the *Noble Discoverer* completed permitted drilling operations and finished temporarily abandoning the Burger A top hole. The rig then disconnected from its anchors, which were permitted to be left in place over the winter, and by October 28 began to travel south to Dutch Harbor, with the ultimate goal of reaching Seattle for off-season repairs and resupply. However, the ship’s propulsion system soon exhibited problems. On November 6, the main engine had to be secured because of severe shaft vibration, and the vessel needed to be towed into Dutch Harbor. On November 16, an attempt to start the main engine resulted in a backfire and the ignition of insulation in the engine room, which was extinguished by the crew. The vessel left Dutch Harbor under tow assist on November 21, and five days later it was towed into Seward, Alaska.

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[35] Letter from Shell to BOEM, dated on August 21, 2012.

The *Kulluk* completed well operations on October 30, but poor weather conditions kept the rig on location until November 8. As with the *Noble Discoverer*, DOI approved Shell's request to leave the *Kulluk* anchors embedded in the seafloor at the drill site, after confirming there would be no safety or environmental impact. Also like with the *Noble Discoverer*, Shell's intent was to tow the *Kulluk* to Seattle for repairs and resupply. On November 22, the *Kulluk* arrived in Dutch Harbor, where an examination by the USCG found 13 deficiencies, although they were not as significant as the ones identified on the *Noble Discoverer*, discussed below, and did not warrant Federal intervention or detention. The *Kulluk* departed for Seattle under tow by the *Aiviq* on December 21.

3. Inspection of the *Noble Discoverer*

While at port in Seward, the USCG conducted a three-day inspection of the *Discoverer* that identified 16 deficiencies, including substantial problems with the main engine, unauthorized piping and equipment modifications, and a failure to adhere to the vessel's Safety Management System (SMS).[36] As a result of these deficiencies, and in particular the problems with the SMS, the USCG placed the vessel under a Port State detention, a serious condition to prevent the rig from departing until corrective actions are implemented, which only occurs as a result of approximately 1% of USCG foreign vessel safety examinations.[37] Some of the deficiencies were remediated quickly. However, several problems were significant enough, including the problems with the propulsion system, that the *Noble Discoverer* has been loaded onto a heavy lift vessel to be dry-towed to Asia for repairs.

The USCG lifted the Port State detention on December 19, 2012. However, based on possible violations of MARPOL, the International Convention for the Prevention of Pollution from Ships, USCG referred the case to the Department of Justice for further investigation.

4. Tow Failure and Grounding of the *Kulluk*

On December 27, in the midst of a series of severe storms in the Gulf of Alaska, the towline between the *Aiviq* and the *Kulluk* parted. Early on December 28, all four engines on the *Aiviq* failed, although one engine was restarted soon afterwards and used to maintain position. As conditions worsened that morning, the first USCG vessel arrived, and by later that day a number of other USCG and Shell-dispatched vessels arrived, including the *Nanuq*, which connected a towline to the *Kulluk*. On December 29, the USCG was able to rescue the eighteen crewmembers from the *Kulluk*, and a second engine was restarted on the *Aiviq*. Severe weather continued, however, and towlines between the *Kulluk* and the *Aiviq* and *Nanuq* parted on December 30. The following morning, the *Aiviq* was able to reattach to the *Kulluk*, but that towline broke that afternoon and the *Kulluk* grounded on Sitkalidak Island on December 31. No injuries were reported and the fuel tanks of the *Kulluk* were not breached, but lifeboat debris washed up on the beach, potentially releasing up to 272 gallons of diesel fuel. More than 700

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[36] Specifically with respect to the SMS, the USCG found that preventive maintenance was not being performed, audit records were not available, and crewmembers were unfamiliar with details of the ship's SMS.

[37] A detention is pursued by the U.S. when the condition of a foreign flag ship or rig does not correspond substantially with the applicable international conventions, and ensures the vessel does not proceed to sea until it can do so without presenting a danger to persons on board or an unreasonable threat of harm to the marine environment.

people and dozens of boats and aircraft participated in the response. The rig was refloated on January 6 and towed to a nearby bay for initial damage assessments. On January 4, the USCG launched a formal marine casualty investigation into the incident.

The causes of the equipment failures on the *Aiviq* and subsequent grounding of the *Kulluk*, as well as the details surrounding development and execution of the tow plan, are the subject of the ongoing USCG investigation. According to members of the maritime industry experienced with Arctic towing operations, tows occur across the Gulf of Alaska year round, and there is nothing inherently unsound about conducting tow operations in this area during winter. However, given the frequency of strong storms and dramatic sea states in this region, operators should incorporate proper planning, risk assessment, and risk mitigation. Additional precautions, such as the use of multiple towlines, should be taken during winter tow operations.[38] Concerning the timing of the *Kulluk* tow from Dutch Harbor, there have been suggestions that Shell attempted to move the rig outside of Alaskan waters before January 1 to avoid having to pay state taxes. The State of Alaska, however, has stated that it would not have attempted to levy taxes on either the *Kulluk* or the *Noble Discoverer*. On February 26, 2013, Shell began towing the *Kulluk* from Kiliuda Bay to Dutch Harbor. It arrived on March 5, 2013 and is currently being prepared for loading onto a heavy lift vessel and dry-tow to Asia for repairs.

E. Shell's Operational Oversight and Management Systems

Complex operations, including offshore oil and gas exploration, require comprehensive, robust and integrated systems for managing risks and ensuring safe operations. These system-based safety programs are referred to generally as Health, Safety, Security, and Environment (HSSE) programs, and cover a broad swath of activities, including risk assessment, employee training, contractor selection, analyzing changes in processes, incident investigations, and considerably more. Examples of specific HSSE programs include the SEMS programs required by BSEE for offshore oil and gas operations, and the International Safety Management Code, created by the International Maritime Organization, and required by USCG for vessels.

Our review assessed Shell's SEMS program and analyzed Shell's overall management, oversight, and risk control processes. This review found that Shell demonstrated all the programmatic design elements of a safety and environmental management program, appeared to comply with BSEE's regulatory requirements for SEMS, and in general Shell promoted a feedback-oriented safety culture. However, the existence of programmatic design elements does not guarantee a functional and effective risk management program, and the review team identified a number of weaknesses indicating that Shell's management systems were insufficiently robust, particularly in the area of contractor oversight, to successfully manage and minimize overall operational risks. Shell's focus appeared to be on compliance with prescriptive safety and environmental regulations required for approvals and authorizations, rather than on a holistic approach to managing and monitoring risks identified during operational planning.

An effective risk management framework at the beginning of a project incorporates a multitude of components, including planning, vessel design, contractor selection, and an

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[38] One such operator conducted a tow of the Kulluk in August 2012, using two tugs. The failed *Kulluk* tow was conducted with only one tug. The tow of the *Kulluk* from Kiliuda Bay to Dutch Harbor is using three tugs.

assessment of regulatory requirements for all facets of the project, including mobilization and demobilization. By focusing on risks and priorities at the beginning of a project, the need for improvisational management or ad hoc responses to unexpected situation is reduced. The review team was unable to find clear evidence that Shell applied an integrated risk management approach to its 2012 operations, other than through the elements required as part of SEMS. SEMS, however, relates only to offshore oil and gas drilling operations, and does not involve overseeing the risks associated with ancillary maritime transportation or logistics activities. A more appropriate risk assessment framework for operations as complex as Arctic offshore drilling programs would also provide for rigorous assessments throughout the program, including, for example, the status and suitability of new vessel and equipment fabrication and retrofitting. This is exactly the type of undertaking that the review team recommends Shell complete in advance of its next proposed drilling season.

It was also not clear the extent to which Shell tailored its global HSSE elements to the 2012 Alaska offshore operations. For example, the Job Safety Analysis checklists used by Shell were generic and not specifically designed for the risks and challenges with operating in the Arctic. The Shell Contractor Health, Safety, and Environmental Handbook also appeared to originate from the global Shell corporate level, without specific adaptations for applicability in the Arctic.

The most significant shortcomings in Shell's management systems were in the area of contractor management and oversight. The review found that several major issues that arose during the 2012 season stemmed at least in part from this fundamental weakness:

- The air permit violations can be traced back to Shell's failure to provide adequate oversight to verify the data from its contractor prior to submitting that data in the air permit applications;
- The delays in the completion of the *Arctic Challenger* and the failure of the containment dome deployment test arose from Shell's lack of rigorous and direct contractor oversight for a complex first-of-its-kind project, as well as the selection of a contractor that did not have ABS or ISO certification for ship design and build work;[39] and
- The anchor dragging and Port State detention of the *Noble Discoverer* can be attributed, in part, to Shell's failure to adequately monitor Noble's compliance with the appropriate management systems on-board the vessel.

The *Arctic Challenger* delays, *Noble Discoverer* deficiencies, and *Kulluk* tow also appeared to result in part from Shell not employing its internal marine expertise in these situations. Shell has acknowledged the need to better integrate its corporate maritime expertise, which resides in its downstream programs, with its upstream exploration program for the Arctic.

The problems with the *Noble Discoverer* also highlight a weakness in Shell's auditing program. In addition to internal audits and independent third party audits, Shell employs a

[39] Shell's selection of Superior appeared to be based on its long-term relationship with that contractor in the Gulf of Mexico. This is not necessarily inappropriate, and may offer certain commercial and operational advantages, but the decision to contract with Superior also should have been informed by a robust analysis of the scope and risks of the ACS project specifically.

process called a "local level audit" that consists of self-assessments using a series of checklists, with little consistency on who performs these or when. A more rigorous audit process might have enabled Shell to identify the deficiencies in the management systems on the *Noble Discoverer* during Shell's investigation of the anchor drag incident. Furthermore, in areas where Shell did identify deficiencies in the management systems on board the *Noble Discoverer*, the review team was not provided evidence of follow-up during the drilling season demonstrating that Shell confirmed those deficiencies were remedied.

Shell has acknowledged shortcomings in its management systems, particularly around contractor oversight, and has indicated that it would take additional steps to address those shortcomings before returning to Arctic operations. One of the management changes being taken by Shell is the implementation of an Integrated Activity Plan (IAP), which is designed to increase operational efficiencies and manage delays. However, if the IAP is to be effective, Shell must ensure that it is focused on identifying operational risks, and is not designed only to improve budgetary decision-making and efficiency.

V. Conclusion

In 2012, Shell started drilling the first wells in the Alaskan Arctic in nearly two decades. To do so, the company assembled and deployed two floating drilling rigs and an armada of support vessels, some of which had been built for purpose and others refurbished. Shell also spent years obtaining the Federal regulatory approvals and authorizations necessary to move forward with its exploration program in both the Beaufort and Chukchi Seas in 2012. And yet, after all the time and investment, when the opportunity finally arrived last summer for Shell to begin exploration drilling in the remote and challenging Alaskan Arctic, Shell fell short of its goal to make discoveries and experienced significant problems that have caused the company to pause its Alaska offshore program.

As detailed in this report, the past drilling season offers lessons for Shell, other companies interested in offshore Arctic exploration, and government regulators. The stakes are high in the Arctic. The oil and gas resources in the Alaskan Arctic are potentially world class, and exploring for them requires years of planning and enormous up front capital expenditures. The risks are substantial and unique as well. As Shell's experience last year makes clear, the waters off Alaska present myriad challenges and dangers during every phase of an offshore operation. A significant accident or spill in the remote and inhospitable Alaskan Arctic could have catastrophic consequences on fragile ecosystems and the people who depend on the ocean for subsistence. For all of these reasons, this review presents seven key principles that are fundamental to safe and responsible offshore oil and gas operations in the uniquely challenging conditions of the Arctic. The review also identifies specific undertakings expected of Shell before it proposes to resume its Arctic offshore program. These undertakings are intended to ensure that Shell has indeed learned from its experience in 2012.

TAB A

Beaufort Sea Exploration Plan
Letter of Approval
August 4, 2011

United States Department of the Interior

BUREAU OF OCEAN ENERGY
MANAGEMENT, REGULATION AND ENFORCEMENT
Alaska Outer Continental Shelf Region
3801 Centerpoint Drive, Suite 500
Anchorage, Alaska 99503-5823

AUG 4 2011

Ms. Susan Childs
Shell Offshore, Inc.
3601 C. Street, Suite 1000
Anchorage, AK 99503

Dear Ms. Childs:

The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) has reviewed Shell's revised OCS Lease Exploration Plan, Camden Bay, Beaufort Sea, Alaska (EP) dated May 2011 and supporting information. The BOEMRE hereby approves the revised EP subject to the eleven conditions below.

1) No exploratory drilling activities may be conducted without an approved Application for Permit to Drill (APD). Shell is advised that its APD must comply with all applicable BOEMRE regulations and Notice to Lessees 2010- N10.

2) No drilling activities may be conducted beyond each casing shoe unless approved by BOEMRE. BOEMRE will evaluate the condition of the well, results of safety equipment tests, the nature and duration of the next phase of the drilling program, existing and forecasted environmental conditions, and the procedures under an approved contingency plan [30 CFR 250.417(c)(2)] that addresses design and operating limitations of the drilling unit as well as the actions necessary (i.e. suspension, curtailment, or modification of drilling or rig operations) to remedy various operational or environmental situations in order to maintain safety and prevent damage to the environment; including implementing well capping and containment or relief well drilling plans.

3) No exploratory drilling activities can be conducted until Shell receives an approved Marine Mammal Protection Act (MMPA) authorization from the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service and the BOEMRE has received a corresponding Endangered Species Act (ESA) Incidental Take Statement (ITS).

4) No exploratory drilling activities can be conducted until Shell receives a New Source Review (NSR)/Title V Outer Continental Shelf air permit or a Prevention of Significant Deterioration (PSD) permit from the EPA, as appropriate.

5) The BOEMRE concludes that Shell has demonstrated that its oil and gas exploration drilling activities will be scheduled and will be located to prevent unreasonable conflicts

with subsistence activities in compliance with Lease Sale's 195 and 202 Lease Stipulation No. 5.

No exploratory drilling activities may be conducted until Shell has documented to the satisfaction of the Regional Supervisor that the monitoring and mitigating measures detailed in the Plan of Cooperation (POC) to prevent unreasonable conflicts with subsistence activities are in place and operational prior to the Camden Bay program drilling season.

Shell must provide this office with daily summaries on the POC activities and daily monitoring results, including, but not limited to Marine Mammal Observer's and local Subsistence Advisors reports and notifications and Shell's responses to each incident. Shell must include the BOEMRE contact number (907) 334-5300 in the Subsistence Advisory Handbook with specific instructions for the Subsistence Advisor to call BOEMRE if they are unable to contact Shell and/or if any subsistence uses conflict has not been resolved. A copy of the handbook must be submitted to this office prior to commencement of exploratory drilling operations.

6) No exploratory drilling activity can be conducted from August 1 through October 31 without an approved site-specific bowhead whale monitoring program in accordance with Lease Stipulation No. 4 As provided for under this stipulation, Shell is seeking an Incidental Harassment Authorization (IHA) from the NMFS in lieu of meeting the requirement of Stipulation No. 4. The BOEMRE will coordinate with the NMFS to assure that the IHA monitoring program and peer review process satisfy the requirements of Stipulation No. 4.

7) Exploratory drilling operations must be suspended by August 25. Exploratory drilling operations may not resume until after Nuiqsut and Kaktovik have completed their bowhead whale subsistence hunting activities and Shell has received approval from BOEMRE. The BOEME will consult with the NMFS to confirm that subsistence hunting activities have been completed.

8) Prior to commencement of exploratory drilling operations, Shell must confirm the final staging location and schedule for mobilizing the designated relief well rig to the drill site and that the response times for commencement and completion of a relief well are consistent with the approved EP.

   Prior to commencement of drilling operations, Shell must demonstrate that the relief well drilling unit meets the requirements of 30 CFR 250.417 and BOEMRE must approve the relief well drilling unit for use in the Beaufort Sea.

   Prior to commencement of drilling operations, Shell must also document that it has the capability to construct a well cellar if deemed necessary as part of the relief well planning effort.

Prior to commencement of exploratory drilling operations, Shell must confirm in writing that relief well equipment and supplies as described in the EP are available and will be made available in time to implement the relief well drilling program.

9) Shell has committed to having a subsea well capping and containment system. The system is currently in the design stage. Prior to commencement of exploratory drilling operations, Shell must provide documentation that the system is designed for the projected worst case discharge conditions for approval by BOEMRE. Shell must also submit documentation on the procedures for deployment, installation and operation of the system under anticipated environmental conditions, including the potential presence of sea ice for approval by BOEMRE. Shell will also be required to conduct a field exercise to demonstrate Shell's ability to deploy the system.

10) No exploratory activities may be conducted until BOEMRE completes Endangered Species Act consultation with the U.S. Fish and Wildlife Service regarding the polar bear critical habitat.

11) Shell's fuel-transfer plan does not fully comply with the requirement of Lease Stipulation No. 6 to surround the fuel barge with oil-spill containment boom before fuel transfer. Prior to conducting exploratory drilling operations, Shell must either modify their fuel-transfer plans to comply with the stipulation or provide justification of how their proposed alternative configuration would provide and equivalent level of response preparedness. This information must be submitted to this office for approval.

As provided by 30 CFR 250.284, the BOEMRE will periodically review the activities conducted under the approved EP and may require Shell to submit updated information or revise the approved EP. BOEMRE plans to conduct this review annually, prior to each subsequent open water season, but may review the plan earlier if it receives substantial new information at an earlier date.

If you have any questions regarding this action, please contact me directly at (907) 334-5300.

Sincerely,

Jeff Walker
Regional Supervisor, Field Operations

TAB B

Chukchi Sea Exploration Plan
Letter of Approval
December 16, 2011

United States Department of the Interior

BUREAU OF OCEAN ENERGY MANAGEMENT
Alaska Outer Continental Shelf Region
3801 Centerpoint Drive, Suite 500
Anchorage, Alaska 99503-5823

DEC 16 2011

Ms. Susan Childs
Shell Gulf of Mexico, Inc.
3601 C Street, Suite 1334
Anchorage, Alaska 99503

Dear Ms. Childs:

The Bureau of Ocean Energy Management (BOEM) Alaska Region has reviewed the Shell Gulf of Mexico Inc. (Shell) Revised 2012 Outer Continental Shelf Lease Exploration Plan, Chukchi Sea, Alaska (EP) for OCS Leases Y-2280, Y-2267, Y-2321, Y-2294, Y-2278, and Y-2324.

BOEM hereby approves the EP subject to the conditions below:

1. Shell must inform the Regional Supervisor for Leasing and Plans (RS/LP) before deviating from activities specified under the EP.

2. No exploratory drilling operations may be conducted under this EP until Shell has satisfied the Bureau of Safety and Environmental Enforcement (BSEE) requirements with respect to the Oil Spill Response Plan (OSRP). Once BSEE's requirements are met, Shell must submit a copy of the OSRP to the RS/LP.

3. No exploratory drilling activities can be conducted without an approved Application for a Permit to Drill (APD) issued by BSEE. Shell must submit a copy of the approved APD to the RS/LP prior to commencing drilling operations.

   Shell is advised that the APD must comply with all applicable BSEE regulations and Notice to Lessee 2010-N10. In accordance with 30 CFR 250.410-418 (MODU), BSEE must receive all required information for APD approval. This includes a current Certificate of Inspection or Letter of Compliance from the U.S. Coast Guard (USCG), current documentation of any operational limitations imposed by an appropriate classification society, and other fitness requirements for the M/V Noble Discoverer (Discoverer) mobile offshore drilling unit required in accordance with 30 CFR 250.417 (Certification of the Drilling Unit).

4. In consideration of the distance to limited support infrastructure on the Chukchi coast, as well as limited drilling experience in the Chukchi Sea, and in keeping with the Secretary of the Interior's desire to proceed cautiously with oil and gas exploration and development in the Chukchi Sea, BOEM will require the following condition designed to reduce risks associated with the proposal by assuring a greater opportunity for response and cleanup in the unlikely event of a late season oil spill.

   No exploratory drilling will be allowed below the last casing point set prior to penetrating a *zone capable of flowing liquid hydrocarbons in measureable quantities into the well* within 38 days of a "trigger date" established each year by BOEM, based upon the date of first ice encroachment over the drill site within any of the last 5 years. For 2012, based upon interpretation of satellite imagery for the period 2007 to 2011, BOEM has determined November 1 as the earliest date in which sea ice covered the Shell drill sites listed in the EP. Accordingly, Shell must not drill below the casing shoe of the last string of casing set before penetrating a zone capable of flowing liquid hydrocarbons in measureable quantities into the well after September 24, 2012. In all other aspects, Shell can continue to operate as conditions permit up to October 31. A new trigger date will be established by the RS/LP for each subsequent year that operations are conducted under the EP.

   Consistent with adaptive management principles, the RS/LP may revise its method for determining the trigger date based upon changes to best available scientific information (i.e., availability of a reliable ice forecasting system capable of predicting with a high degree of certainty when ice will likely encroach upon the drill site locations).

5. No exploratory drilling activities can be conducted until Shell has received an approved Marine Mammal Protection Act (MMPA) authorization from the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) for the specific activity, and the RS/LP has received a corresponding Endangered Species Act Incidental Take Statement (ITS) for threatened, endangered and protected species. Shell must submit a copy of the approved IHA or LOA to the RS/LP prior to commencing operations.

6. Shell's EP includes a marine mammal monitoring program and Shell has applied for an Incidental Harassment Authorization (IHA) from the National Marine Fisheries Service (NMFS) and a Letter of Authorization (LOA) from the US Fish and Wildlife Service (USFWS). The EP describes Shell's plans for aerial monitoring, on-vessel marine mammal observers, real time acoustical recorders, and site-specific sound source verification to confirm acoustic safety zones prior to commencement of drilling operations. The RS/LP, in consultation with the NMFS and the USFWS, may modify lease operations as necessary to comply with the requirements of authorizations issued by NMFS and USFWS.

7. Shell has developed a Plan of Cooperation (POC) designed to prevent unreasonable conflicts with subsistence activities in compliance with Lease Stipulation 5 (Conflict

Avoidance Mechanisms to Protect Subsistence Whaling and Other Subsistence-harvest Activities). Stipulation 5 applies to support activities, such as vessel and aircraft traffic, that traverse the blocks listed or Federal waters landward of the sale during periods of subsistence use regardless of lease location.

No support activities may be conducted on the blocks listed or on Federal waters landward of the Sale 193 area until Shell has documented to the satisfaction of the RS/LP that the monitoring and mitigating measures detailed in the POC to prevent unreasonable conflicts with subsistence activities for the Chukchi Sea program are in place and operational prior to mobilization of each drilling season.

BOEM retains the authority to restrict lease-related use if it is determined that it is necessary to prevent unreasonable conflicts with local subsistence hunting activities. Shell must provide this office with daily summaries on POC activities and daily monitoring results including but not limited to Marine Mammal Observers' and local Subsistence Advisors' reports and notifications and Shell's responses to each incident. Shell must also include the BOEM contact number (907) 334-5200 in the Subsistence Advisors Handbook with specific instructions for the Subsistence Advisors to call BOEM if they are unable to contact Shell and/or if any subsistence use conflict has not been resolved. A copy of the handbook must be submitted to this office prior to commencement of exploratory drilling operations.

The POC states that Shell plans to have continuing engagement with local subsistence users to discuss and possibly further supplement the POC. Shell must inform the RS/LP (or designee) promptly of any deviation from or alteration of the POC that Shell intends to take as a result of these ongoing community meetings.

Shell shall inform the RS/LP of any presentation/meeting Shell intends to conduct under the POC to allow the RS/LP (or designee) to attend such engagement.

8. Prior to commencement of exploratory drilling operations, Shell must confirm the final staging location and schedule for mobilizing the designated relief well rig to the drill site and the consistency of response times for commencement and completion of a relief well with the approved EP. Confirmation must be sent to the RS/LP.

   Prior to commencement of drilling operations, Shell must demonstrate that the relief well drilling unit meets the requirements of 30 CFR 250.417 and confirm that they have received approval from BSEE for the relief well drilling unit for use in the Chukchi Sea. Shell must present a copy of BSEE's approval letter to the RS/LP prior to commencing operations.

9. Shell has committed to having a subsea well capping and containment system. The system is currently in the design stage. Prior to commencement of exploratory drilling operations, Shell must confirm that they have documented and received approval from BSEE that the system is designed for the projected worst case discharge conditions. Shell must also confirm that they have documented and received approval from BSEE

regarding the procedures for deployment, installation and operation of the system under anticipated environmental conditions, including the potential presence of sea ice.

Shell will also be required to conduct a field exercise to demonstrate their ability to deploy the system. Shell must confirm that they are in compliance with any agreement concerning well capping and containment reached with BSEE.

Shell must present a copy of BSEE's approval letter to the RS/LP prior to commencing operations.

10. An orientation program that will satisfy the requirements of Lease Stipulation 2 (Orientation Program) must be submitted to the RS/LP annually for approval prior to commencing drilling operations.

11. If Shell transits to the Chukchi Sea from the Beaufort Sea during the fall bowhead whale migration and before or during Barrow's fall bowhead whale subsistence hunt, Shell shall meet with the appropriate whaling captains to coordinate vessel transit routes westward through the Beaufort Sea to prevent any deflection of the bowhead whale migration and any conflicts with Barrow's fall whaling season. Emergency operations will take precedence over this condition.

12. The Marine Mammal Observers (MMOs) on vessels underway in the Chukchi Sea must monitor the ocean waters near the vessel for surfacing whales. If a surfacing whale is observed within 300 ft (100 m) of the vessel, the vessel must disengage propellers to avoid potential propeller injury to the whale (prop strike) and, to a lesser degree, collision. Propellers must remain disengaged until the whale moves beyond 300 ft (100 m). Safety of the vessel and its personnel will take precedence over this condition.

13. In addition to the measures committed to by Shell in its Bird Strike Avoidance and Lighting Plan to comply with Lease Stipulation 7 (Lighting of Lease Structures to Minimize Effects to Spectacled and Steller's Eider), the following measures also are required pursuant to the September 3, 2009, FWS *Biological Opinion for Beaufort and Chukchi Sea Program Area Lease Sales and Associated Seismic Surveys and Exploratory Drilling*:

    a. Routine deck searches for dead or injured birds should be performed, especially during or following periods of darkness or inclement weather. Most avian collisions occur during periods of darkness and/or inclement weather such as rain or fog.

    b. Birds perching on ship structures (such as antennas or rigging) should be allowed to rest and depart on their own.

    c. All bird fatalities shall be documented and reported within 3 days to the RS/LP. Minimum information will include species, date/time, location, weather, identification of the vessel involved and its operational status when the strike occurred. Carcasses should be returned to the sea.

Photographs are not required, but would be very helpful in verifying species as part of the collision report. If photographs are taken, FWS has requested the following views of any birds killed by collision: wingspread (if possible), top and bottom views, and head.

If a bird strikes and remains on the vessel, leave it to recover and depart on its own. If necessary to take it out of harm's way, move it to a dry place where it can depart on its own. If the bird does not depart after about 12 hours but is still alive, carefully return it to the sea surface.

14. Shell's fuel-transfer plan does not fully comply with the requirements of Lease Stipulation 6 to surround the fuel barge with oil-spill containment boom before fuel transfer. Prior to conducting exploratory drilling operations, Shell must either modify its fuel-transfer plans to comply with the stipulation or provide justification of how the alternative configuration would provide an equivalent level of response preparedness. This information must be submitted to the RS/LP for approval.

15. No exploratory activities may be conducted until BOEM completes its ongoing Endangered Species Act consultation with the U.S. Fish and Wildlife Service.

As provided by 30 CFR 550.284, BOEM will annually conduct a pre/post review of the activities conducted under the approved EP and may require Shell to submit updated information or revise the approved EP. BOEM plans to conduct this review annually, prior to each subsequent open water season, but may review the plan earlier if it receives substantial new information.

If you have any questions regarding this action, please contact me directly at (907) 334-5200.

Sincerely,

David W. Johnston
Regional Supervisor, Leasing and Plans.

cc: State of Alaska - Office of the Governor

Office of the Governor - EXECUTIVE OFFICE ANCH, ATT: Jeffrey Jones, Special Staff Assistant
Department of Natural Resources OPM-OFFICE PRJ MGMT/PERMIT, ATT: Sara Longan
Alaska Oil & Gas Conservation Commission, ATT: Steve Davies
Department of Natural Resources Division of Geological and Geophysical Surveys, ATT: Patty Burns
Department of Environmental Conservation Commissioner's Office
Department of Environmental Conservation Commissioner's Office, Prog Coordinator, ATT: Gary Mendivil
U.S. Department of Environmental Conservation, Division of Water
U.S. Department of Environmental Conservation, Division of Air
U.S. Department of Environmental Conservation, Spill Response
U.S. Department of Environmental Conservation, Division of Spill Prevention & Response, ATT: Larry Iwamoto
U.S. Department of Environmental Conservation, Division of Spill Prevention & Response, ATT. Dale W. Gardner
U.S. Department of the Interior, Office of the Secretary, Environmental Policy and Compliance, ATT: Pamela Bergmann
U.S. Fish and Wildlife Service Region 7, Regional Director, ATT. Geoff Haskett
U.S. Fish & Wildlife Service – Endangered Species, ATT: Tim Jennings
U.S. Fish & Wildlife Service – Endangered Species, ATT: Ted Swem
U.S. Fish & Wildlife Service – Marine Mammal Management, ATT: Craig Perham
U.S. Fish & Wildlife Service – Marine Mammal Management, ATT: Christopher Putnam
U.S. Fish & Wildlife Service – Marine Mammal Management, ATT: Joel GarlichMiller
U.S. Fish & Wildlife Service – Northern Alaska Ecological SVCS
U.S. Fish & Wildlife Service – Conservation Planning Branch, ATT: Jewel Bennett
U.S. Fish & Wildlife Service – Conservation Planning Assistance, ATT: Louise Smith
Alaska Region National Marine Fisheries Service - Alaska Region, ATT: James W. Balsiger
Alaska Region National Marine Fisheries Service, ATT: Brad Smith
U.S. NMFS NOAA – Office of Protected Species, ATT: Michael Payne
U.S. Army Corps of Engineers Regulatory Branch Alaska District, ATT: Chief Kevin Morgan
U.S. Environmental Protection Agency Region X Alaska, ATT: Diane Soderland
U.S. Coast Guard Alaska Region, ATT: U.S. Coast Guard Commander
U.S. Coast Guard Alaska Region, ATT: COMMANDING OFFICER MARINE SAFETY OFFICE
U.S. National Park Service, ATT: Glen Yankus
Mayor of Northwest Arctic Borough
Mayor of North Slope Borough
North Slope Borough Planning Department, ATT: Dan Forrester
North Slope Borough Dept of Wildlife Management, ATT: Taqulik Hepa
North Slope Borough Dept of Wildlife Management, ATT: Robert Suydam
North Slope Borough, ATT: Andrew Mack
North Slope Borough, ATT: Tom Lohman
Mayor of Kaktovik
Mayor of Nuiqsut
Mayor of Barrow
Mayor of Wainwright
Native Village of Wainwright
Mayor of Point Hope
Native Village of Point Hope
Native Village of Point Lay
Native Village of Kotzebue
Inupiat Community of the Arctic Slope
Alaska Eskimo Whaling Commission, ATT Harry Brower
Alaska Eskimo Whaling Commission, ATT: Janice Meadows
Alaska Beluga Whale Committee
Alaska Nanuuq Commission
Alaska Ice Seal Committee
Eskimo Walrus Commission
Earthjustice, ATT: Erik Grafe
Alaska Wilderness League, ATT: David Dickson

Center for Biological Diversity, ATT: Rebecca Noblin
Audubon Alaska, ATT: Stanley E. Senner
Defenders of Wildlife, ATT: Richard Charter
Natural Resource Defense Council, ATT: Charles M. Clusen
Northern Alaska Environmental Center, Pamela A. Miller
Ocean Conservancy, Andrew Hartsig
Pacific Oceana, ATT: Jim Ayers
Pacific Environment, ATT: Whit Sheard
Sierra Club, Trish Rolfe
The Wilderness Society, ATT: Eleanor Huffines
World Wildlife Fund, ATT: Layla Hughes

TAB C

Letter from Marvin Odum to S. Elizabeth Birnbaum
May 14, 2010

Shell Oil Company
Marvin E. Odum
President
One Shell Plaza
P. O. Box 2463
Houston, TX 77252-2463

May 14, 2010

S. Elizabeth Birnbaum
1849 C Street, NW
United States Department of the Interior
Minerals Management Service
Washington, DC 20240

Dear Director Birnbaum,

I am writing in response to your letter of May 6, 2010 regarding Shell's proposed exploratory drilling activity in the Chukchi Sea and Beaufort Sea. You requested information that may be pertinent to the review of Shell's Applications to Drill (APDs) that Minerals Management Service (MMS) will undertake in light of the Deepwater Horizon incident; and information about additional safety procedures that Shell plans to undertake in light of that incident.

Before responding to your request, I want to acknowledge the tragedy of the Gulf of Mexico (GOM) blowout and oil spill. I commend the Department of Interior (DOI) for its role in coordinating the unprecedented joint industry-government response effort. Shell is a full participant in this response; and additional Shell resources and expertise are available if needed.

I also commend the DOI for the urgency with which it is pursuing an investigation into the cause of the blowout. Root cause analyses are critically important in order for industry and government to identify steps that should be taken to ensure the safety and integrity of oil and gas operations on the Outer Continental Shelf (OCS). At Shell, we have already begun to enhance our operational excellence in light of this incident and we will continuously make adjustments as new learnings are revealed. We do not believe that best practices are static.

Regarding Shell's Chukchi and Beaufort Sea leases, please consider the following important points. First, Shell is committed to undertaking a safe and environmentally responsible exploration program in the Chukchi Sea and Beaufort Sea in 2010. Second, MMS has diligently and proactively challenged and reviewed Shell's 2010 Arctic exploration drilling program. On Thursday, May 13, 2010, the 9th Circuit Court of Appeals upheld the MMS's approvals of our 2010 exploration plans. At every step, Shell has worked with MMS, other federal agencies, the State of Alaska, and local communities to develop a program that meets the highest operational and environmental standards. In response to the recent MMS Safety Alert, Shell will check each point raised in the letter against our internal audit of operations. Third, following the Deepwater Horizon incident, Shell initiated its own thorough review of the prevention and contingency plans for our 2010 Arctic exploration plans

I am confident that we are ready to conduct the 2010 Arctic exploratory program safely and, I want to be clear, the accountability for this program rests with Shell.

I appreciate the opportunity to provide information here about Shell's 2010 Arctic exploration program. I will discuss (1) how our program differs significantly from the GOM deepwater exploratory wells; (2) the oil spill prevention, mitigation and response plans included in Shell's current 2010 Arctic exploration plans; and (3) the additional measures that Shell has identified to add to the 2010 exploration plans in light of the GOM incident.

1. Differences between exploration in Alaska and deepwater exploration in the Gulf of Mexico

Drilling conditions for Shell's proposed 2010 Alaska wells are typical of well conditions that have been safely and effectively addressed for more than 30 years. They are much different than those in the GOM deepwater, most notably in terms of water depth and pressure. The Deepwater Horizon was drilling in 5,000 feet of water to a depth of 18,000 feet. This type of well is technically more complex than those wells planned in the Arctic for 2010. The pressure encountered in the Macondo well was about 15,000 psi based on mud weight at total depth. This is 2 to 3 times greater than what Shell expects to encounter in Alaska where 2010 drilling will be in approximately 150 feet of water to a depth of approximately 7,000 to 8,000 feet in the Chukchi and up to approximately 10,200 feet in the Beaufort. We are expecting a pressure at total depth of no more than 6,000 psi in any of these 2010 wells.

Shell has developed extensive reservoir pressure models based on previously drilled wells in the Chukchi and Beaufort Seas. Knowing the pressure profile of the previously drilled wells reduces uncertainty in pore pressure prediction for the 2010 wells. Due to the difference in expected down-hole pressure of the Macondo well versus our planned 2010 wells, our margin to safely operate in Alaska is much greater than that experienced by the Deepwater Horizon. Our biggest safety advantage is the water depth that will allow us to detect and respond to an event quickly and appropriately. Even in the highly unlikely event of Shell's drilling riser failing, the remaining drilling fluid below the seafloor would effectively stop any well flow in such a low-pressure system.

2. Current practices and our plans, which includes our mitigation for prevention and response

Shell has design standards and practices that have enabled us to successfully and safely drill many deepwater and shallow water wells worldwide. These practices include:

a. Shell generally does not install full string casings through high-pressure zones. It is our practice to install and cement liners then to install and cement casing tiebacks. This practice delivers better cementation and hydraulic isolation across the zone of interest as well as the opportunity to install a liner top packer. We test our liner tops both in pressure and with an inflow test prior to installing a tieback string of casing back to the wellhead; this ensures we have hydraulic isolation prior to installing the tieback casing.

b. Shell has a two-barrier policy, with each barrier validated in the direction of potential flow for all well operations. During the transition from drilling to temporary abandonment and prior to disconnecting the subsea Blow Out Preventer (BOP) from the well, a mechanical barrier, in addition to the cement and shoe track or plugs, must be installed and tested in all production casings thus ensuring that at least two independent barriers are in place.
c. Shell policy requires that all casing hangers be locked down and that the seals be engaged. All seals on casing hangers are tested to ensure that we have two independent validated barriers at all times.

Shell will rigorously apply an appropriate similar level of standards in all well operations on the Alaska OCS. Because of lower anticipated down-hole pressure in the planned 2010 Alaska wells, all of the mechanical barriers included in Shell's well design (including contingency equipment) have inherently higher overall safety margin between operating pressure and mechanical barrier design pressures.

Shell's BOP has been and continues to be extensively inspected and tested by 3rd party specialists. The BOP has been validated to comply with the original equipment manufacturer specifications, in accordance with API Recommend Practice No. 53. Further inspection and testing has been performed to assure the reliability of the BOP and that all functions will be performed as necessary including shearing the drill pipe. Before initiating operations, the BOP will have a final test in Dutch Harbor and MMS inspection verification. Shell's BOP is well suited for operating in the Arctic. Our BOP control function is rapid and secure given its full hydraulic control system and relatively shallow working depth. In addition we will have a second BOP available in Dutch Harbor (or closer to drilling locations) for relief well drilling and other intervention techniques. An acoustic switch was considered for our Alaska wells, however placement on some of the components in the mud-line cellar and the shallow water depth diminishes the effectiveness of this approach. Specifically, the angles of transmission are too extreme and therefore unreliable when the secondary activation vessel moves a sufficient distance from the rig.

Shell's 2010 Arctic wells are exploratory and will not be converted for future production operations, thus production casing will not be installed. It is our understanding that production casing had just been run in the Macondo well and may have been a factor in the GOM incident.

The following items are safety aspects of our 2010 plans

a. We have regional Blow Out Contingency Plans, one for the Chukchi Sea and one for the Beaufort. We also have specific relief well drilling plans for each well, which must be approved by the MMS.
b. We understand MMS inspectors will be housed on board the Frontier Discoverer 24-hours per day/7 days per week throughout the 2010 drilling program.
c. We have a comprehensive Critical Operations and Curtail Plan with specific procedures for suspending operations in case of emergency evacuation that properly seal and secure a well site.
d. We will follow all current MMS plug and abandon procedures; for example, MMS requires a competent cement plug, the top of which must extend to 500' above the top of the upper most hydrocarbon-bearing zone. In addition to the required procedures and as an additional safety barrier, we will add a mechanical plug and appropriately test leak paths.
e. We have simultaneous operational plans (SIMOPS) that will be managed to avoid well control incidents. In addition, we have full time SIMOPS coordinators to ensure no inappropriate simultaneous operations are conducted. For example, we will not induce an underbalance while waiting on cement. We will have a BOP, riser, and surface casing in place prior to drilling into known

or predicted productive gas or liquid hydrocarbon zones to isolate fragile overlying intervals to avoid fracturing under reservoir pressure.

f. We can determine drill string position to avoid placing a tooljoint in the sheer/blind rams, a process that is much easier in shallow water than in deep water.

g. Shell's primary relief well plan for Arctic drilling remains disconnecting the Frontier Discoverer from the wellbore and utilizing the Frontier Discoverer to spud a relief well expeditiously. This remains a robust plan due to the well control procedures and shorter response times as explained above. One of the reasons for selecting the Frontier Discoverer drill ship is its ability to safely and quickly depart from the well location in the event of unmanageable ice. In the event of a blowout, the same riser and anchor disconnect technologies make it probable that the Discoverer and its crew will be moved out of harms way thereby allowing it to drill a relief well. We have prepared for this circumstance by ensuring that we have a full extra set of equipment including a BOP, anchors, drill pipes and casings as well as drilling supplies on or quickly available to the Discoverer. In the unlikely event of a blowout resulting in the loss of the Discoverer, Shell would mobilize the Shell owned Kulluk drilling vessel that is capable of drilling same season relief wells in the Alaska OCS. Shell has made significant capital improvements to the Kulluk and is currently managing rig readiness.

Oil Discharge Prevention and Response Plan

Shell will be ready to respond with oil spill response assets in one hour. Shell has an unprecedented three-tier system consisting of an on-site dedicated oil spill response fleet, near-shore barges and oil spill response vessels, and onshore oil spill response teams. These resources are staffed with trained crews and supported by Alaska Clean Seas and Arctic Slope Regional Corporation.

Arctic conditions create differences in responding to oil in cold and ice conditions. Differences in evaporation rates, viscosity and weathering provide greater opportunities to recover oil. Shell and MMS were among the participants in the SINTEF Joint Industry Project that concluded in 2009. This project demonstrated that, in Arctic conditions, ice can aid oil spill response by slowing oil weathering, dampening waves, preventing oil from spreading over large distances, and allowing more time to respond.

3. Additional measures that we have identified to add in light of the incident in the Gulf of Mexico

Our program is robust and includes high safety and mitigation standards to enable safe operations in the Arctic; we have taken early lessons from the GOM incident and incorporated them into our 2010 drilling plans.

Well control enhancement

a. In 2010, instead of whole coring objective reservoirs in initial penetrations, we will first evaluate formations using drillpipe- or wireline-conveyed logging tools, and potentially rotary sidewall cores, in the original wellbore. Any whole coring would be performed in a bypass hole only after reservoir parameters (pressure, fluid content, temperature, etc.) have been ascertained in the original wellbore. This will further reduce the risk of a "kick" or unwanted flow in the original wellbore.

b. BOP testing frequency will be increased from 14-day intervals to 7-day intervals to further assure proper functioning.

Enhancements to Blow Out Preventers

a. We are evaluating the risks-benefits of an additional set of shear rams, which would provide redundancy for shear blind capabilities. Such changes require careful consideration as it represents a significant departure from our successful and reliable well control training and practices.
b. A remote hot stab system is being designed that will allow a Remote Operated Vehicle (ROV), diver, or support vessel to actuate the BOP from a sled on the seafloor - a safe distance away from the well connected by an umbilical.
c. A subsea BOP remote operating panel will be relocated from the bottom of the BOP to the top for easier diver or ROV intervention. This provides two ROV/diver intervention options.

Remote Operating Vehicles and Divers

a. We will have a fully functional work-class ROV for BOP intervention on one of our previously identified support vessels in addition to the ROVs on the drilling rig and science vessel.
b. We will have backup launch and recovery capability for divers on a support vessel. If the Frontier Discoverer is disabled, this plan provides for redundant diver support capability.

Containment and Response

a. We will have a pre-fabricated coffer dam pre-staged in Alaska that will take into consideration issues associated with hydrate formation i.e. GOM, and gas/oil separation. We will locate the dome for immediate deployment, if required.
b. If needed, we will also apply dispersant under water at the source of any oil flow that might occur; however the dispersant would not be used until all necessary permits are acquired.

In closing, I have complete confidence in the technical integrity of our well plans. As described herein, those plans employ a layered approach designed to prevent all types of incidents, including well control incidents like that experienced in the Gulf of Mexico. Furthermore, I also have complete confidence in our ability to execute the 2010 Chukchi Sea and Beaufort Sea exploration plans in a safe and environmentally responsible manner. Those exploration plans, which reflect 60 years of experience conducting exploration and development drilling on OCS lands and were developed over the course of the last three years with direct input from the MMS, other federal regulatory agencies, the state of Alaska and local communities, meet the highest operational and environmental standards.

Please let me know if you have any additional questions. We look forward to receiving your final authorizations to proceed with our 2010 exploration plans.

Sincerely,

Marvin E. Odum, President
Shell Oil Company

cc: Governor Parnell, Senator Murkowski, Senator Begich & Rep. Young

United States Department of the Interior

BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
WASHINGTON, DC 20240-0001

In Reply Refer To:
Mail Stop HE3327

FEB 19 2013

Mr. Sean Churchfield
Shell Offshore, Incorporated
3601 C Street, Suite 1000
Anchorage, Alaska 99503

Dear Mr. Churchfield:

On September 5, 2012, the Oil Spill Response Division (OSRD) of the Bureau of Safety and Environmental Enforcement (BSEE) conducted a government initiated unannounced exercise (GIUE), under our authority in 30 CFR 254.42(g) to conduct unannounced drills and in accordance with the National Preparedness for Response Exercise Program (PREP) guidelines. The participation of Shell Offshore, Incorporated, in this GIUE demonstrated your preparedness to respond to a discharge as described in your Beaufort Sea Regional Exploration Program Oil Spill Response Plan dated May 2011. We have concluded that you successfully completed this exercise by meeting the scope and objectives established by OSRD.

You may use activities conducted during this exercise to fulfill your triennial exercise compliance requirements found within 30 CFR 254.42: "Exercises for your response personnel and equipment." It is your responsibility to maintain a record of any aspect of this exercise you use toward your triennial training requirement as per 30 CFR 254.42(e).

If you have questions please do not hesitate to contact Ms. Christy Bohl, Senior Analyst, Alaska Region Unit at Christy.Bohl@bsee.gov, (907) 334-5309 or 3801 Centerpoint Drive, Suite 500, Mail Stop AE500, Anchorage, Alaska 99503.

Sincerely,

Kelly Ann Schrayp

for: David M. Moore
Chief, Oil Spill Response Division

Memorandum for Record

October 23, 2012

To: David M. Moore, Chief, OSRD

Thru: Kelly Schnapp, Senior Advisor, OSRD

From: Christy Bohl, Senior Analyst, Alaska Region Unit, OSRD

Subject: Shell North Slope Equipment Inspection September 24 – 28, 2012

On September 24 – 28, 2012, I conducted oil spill response equipment inspections of Shell Offshore, Inc. (Shell) assets identified in their Chukchi and Beaufort Seas Regional Exploration Program Oil Spill Response Plans that were not inspected during the May 2012 inspection in Valdez, Alaska. The intent of the trip was to also conduct equipment deployment drills at locations in the Beaufort Sea, Chukchi Sea and Wainwright, Alaska, but due to weather conditions and the ban on operations in the Beaufort Sea until the Native villages completed their whaling, these drills could not be completed.

The equipment inspections were conducted concurrently with the United States Coast Guard (USCG) National Strike Force Coordination Center (NSFCC) Response Resource Inventory Preparedness Assessment Visit of Alaska Clean Seas (ACS), Shell's primary oil spill removal organization (OSRO). The NSFCC inspectors were conducting a comprehensive inspection of ACS's training and maintenance records and verifying equipment inventories and operability for ACS OSRO classification purposes. The NSFCC will provide BSEE a copy of their final inspection report which will be used to verify presence of equipment that could not be inspected by me during the visit. MST1 Eben Wilson from the NSFCC accompanied me on all Oil Spill Response Division (OSRD) inspections.

Safety was a prime focus during each inspection and prior to entering the warehouses, storage yards or vessels we were provided a safety briefing which included required personal protective equipment (PPE) and muster points in the event of an emergency. In instances where we lacked appropriate PPE we were provide the necessary equipment to complete the inspections. We were similarly provided a safety briefing for the flight on the USCG helicopter out to the Motor Vessel (MV) Aiviq in the Beaufort Sea.

Equipment Inspection Alaska Clean Seas, Prudhoe Bay, Alaska

Upon arrival in Prudhoe Bay, I contacted Mr. Bark Lloyd, General Manager of ACS at 0920 and notified him that we would be arriving in approximately one hour to conduct an unannounced inspection of their response equipment. At 1015 we arrived at the ACS office at which point I identified myself and stated the purpose of our visit. We were escorted to the training room and provided an in-brief on ACS operations and safety protocols and was provided an escort to assist with our inspection.

Shell Oil Spill Response Assets for Chukchi and Beaufort Seas				
Unit/Inventory	**Quantity**	**Condition**	**Operational Status**	**Date Inspected**
Task Force 3 – Beaufort Sea				
Oil Storage Tanker	1	Good	Location of vessel verified by Marine Vessel Exchange Vessel Tracking System	9/27/2012
Task Force 4 – Beaufort Sea				
Vessel of Opportunity Skimming System (VOSS) MV Aiviq	1	Good	Yes	9/25/2012
Transrec 150 Umbilical Weir Skimmer	1	Good	System starts and moves but full operability must be demonstrated at later date	9/25/2012
Task Force 5 - Beaufort Sea				
VOSS MV Sisuaq	1	Good	Yes	9/25/2012
Transrec 150 Umbilical Weir Skimmer	1	Good	System starts and moves but full operability must be demonstrated at later date	9/25/2012
Task Force 7 – Wainwright				
Conventional Boom	10,000’	Good	Yes	9/26/2012
Coastal Boom	4,000’	Good	Yes	9/26/2012
Shoreline Guardian Boom	4,000’	Good	Yes	9/26/2012
Landing Craft, 26’ – 32’	4	Good	Yes	9/26/2012
Workboat	6	Good	Yes – Vessels located Prudhoe Bay	9/24/2012
Task Force 8 – Prudhoe Bay				
Oleophilic Skimmers	20	Good	Yes – representative sample	9/24/2012
Storage Bladders (500 – 2,640 gal)	36	Unknown	Awaiting NSFCC report	
Portable Folding Tank (2,500 gal)	50	Good	Yes – representative sample	9/24/2012
IMO Tank (6,000 gal)	1	Unknown	Awaiting NSFCC report	

Following the in-brief we received a briefing on the ACS equipment maintenance computer program and randomly selected equipment from the inventory to view inspection and maintenance records. Equipment inspections are conducted on a monthly basis and required preventive maintenance and equipment repair is documented for each piece of equipment. ACS is in compliance with 30 CFR 254.43 Maintenance and periodic inspection of response equipment.

Shell's OSRP does not specifically identify the exact equipment to be used for near shore and shoreline response, I therefore inspected equipment types that are identified in the ACS Technical Manual as part of the response tactics for those environments. Sample tactics can be found in Attachment 1. Skimmers cited in the tactics are primarily disc and brush type skimmers. Shell's OSRP also calls for six vessels to be transported to the Chukchi for near shore and shoreline response so I inspected shallow draft boats such as air boats and landing craft that would most likely be used in a response.

<u>Vessels</u>

The Shell OSRPs call for ACS to provide six boats to support shoreline response both in the Chukchi and the Beaufort Seas. ACS maintains an inventory of airboats, inflatables, landing craft, and bay and island boats to conduct their operations. We viewed boats of each type and had ACS start various boats to demonstrate operability. All vessels selected for startup started immediately and appeared to be well maintained and in good condition.

Airboat Landing Craft

Airboat

Shallow-Draft Boat

Inflatable Boat

Airboats

Airboat and Munson Boat

Landing Craft and Island Boat

Island Boats and Bay Boats

Island Boats

Storage

ACS maintains an inventory of portable storage devices such as fast tanks, folding tanks and mini-barges for recovered fluids. We inspected various barges and folding tanks at locations around Prudhoe Bay. We also inspected equipment staged along river banks for rapid deployment in the event of a spill. The folding tanks all appeared to be new and in excellent condition. The mini-barges also appeared to be in good condition.

Mini-barges

Mini-barges – 249 barrel (bbl) capacity

Mini-barge – 650 bbl capacity

Mini-barge – 249 bbl staged offshore

Mini-barge – 249 bbl staged offshore

Folding Storage Tanks

Large Folding Storage Tank

Small Folding Storage Tank

Deployed Folding Storage Tank

Access to Pre-Staged Storage Tanks

Pre-Staged Equipment Connexes

Folding Storage Tanks

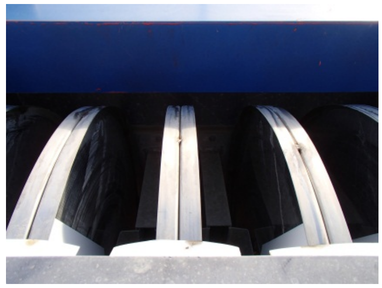
Folding Storage Tanks

Folding Storage Tanks

Skimmers

ACS technicians assembled, started and operated the T-54 Disc Skimmer, the Crucial Fuzzy Disc Skimmer, and the MI-30 Disc Skimmer. All hoses and connectors were in good condition. The power packs started immediately and the skimmer heads were rotated demonstrating operability. Pump units were also started and operated.

T-54 Disc Skimmer



T-54 Disc Skimmer

Drum Skimmer

Crucial Fuzzy Disc Skimmers

Crucial Fuzzy Disc Skimmer in Operation

MI-30 Disc Skimmer

MI-30 Power Pack

MI-30 Disc Skimmers and Pumps

Lori Side Collector 3-Brush Skimmers (LSC 3)

LSC 3 Skimmers on Landing Craft Agvik

Boom

Open Water Containment Boom

New Open Water Containment Boom

Open Water Containment Boom

Hydro-Fire Boom Power Pack

Hydro-Fire Boom

3M Fire Boom

Protected Water Boom

Protected Water Boom

Protected Water Boom

Kepner Light Ocean Boom

Shore Seal Boom

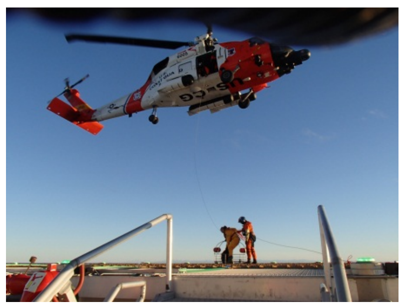
NOFI Rapid Deployment Boom

We also inspected a wide variety of containment, fire and exclusion boom maintained in the ACS inventory. All boom appeared to be in good condition.

<u>Equipment Inspection - Beaufort Sea</u>

The intent of the Beaufort Sea inspections was to verify the presence of two Transrec 150 skimmers on Vessel of Opportunity Skimming Systems (VOSS) on the Shell vessels Aiviq and Sisuaq and to conduct a deployment drill to test Shell’s ability to mobilize and deploy response equipment as described in the Beaufort Sea OSRP in the area of operation. As stated above, due to the ban on exploration activities during the Native village’s whaling season, equipment deployment drills could not be conducted.

<u>Transfer from MV Aiviq Helideck to USCG Helicopter</u>



In an attempt to conduct unannounced inspections, we utilized a USCG helicopter for transport out to the MV Aiviq. The advance coordination between Shell and the USCG for air operations procedures greatly limited the unannounced aspect of the inspection. Also because the vessels were under way, the USCG pilots were unable to land on the helideck so they had to coordinate operations with the vessels. Instead of setting down on the vessel we were lowered to the deck and brought back aboard the aircraft via a basket.

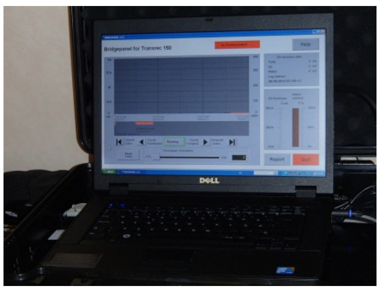
Once we were aboard the Aiviq we were provided a safety briefing on required PPE, ship emergency signals and muster points for the vessel. We were then escorted to the vessel’s main conference room where we introduced ourselves and the purpose of our visit. The only equipment we could inspect given the operational restrictions were the Transrec 150 skimmers located on the Aiviq and the Sisuaq and that was limited to starting the power unit and raising the skimming head off the deck. The lead oil spill response technician provided a job safety analysis briefing for the operation of the skimmer and outlined the scope of the activities they would be conducting for our inspection. He also contacted the Sisuaq and had the vessel move to our location to allow us to view the Transrec 150 skimmer located on that vessel.

VOSS MV Aiviq -Transrec Skimmer

Transrec 150 Skimmer – Aiviq

Transrec 150 Skimmer Head

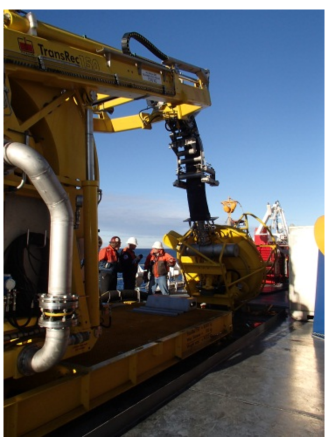
Transrec 150 Skimmer Power Pack



Transrec 150 – Monitoring Program

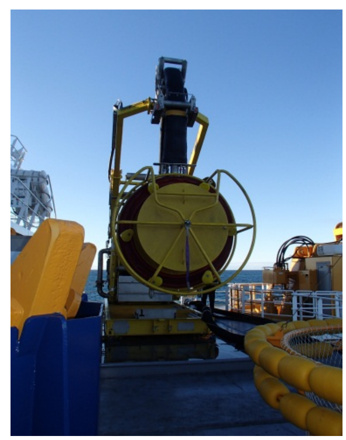
Transrec 150 – Remote Control

Transrec 150 – Hose and Connectors



Transrec 150 Skimmer

Transrec 150 – Storage Reel



Transrec 150 – Skimmer Head Raised

Following the briefing we were escorted out to the skimmer unit. An oil spill response technician connected the power unit to the skimmer while the skimmer operator provided a description of the skimmer, its capabilities and normal mode of operation. He showed us the remote control unit used for maneuvering the skimmer head and regulating skimming operations and the computer program that monitors and tracks the skimmer's performance and recovery rate. Following the skimmer briefing, unit power pack was started and the operator raised the skimmer head and briefly engaged the pump unit. The Transrec is a new skimmer and in excellent condition.

The Sisuaq arrived on site at approximately 1630 and began preparations to operate the Transrec 150 skimmer located on its deck. From the bridge of the Aiviq we observed the skimmer operator on the Sisuaq raise and manipulate the skimmer head as was done with the unit on the Aiviq. This inspection verified the presence and limited operability of the two pieces of equipment for Task Forces 4 and 5 that were unavailable for inspection during the May inspection in Valdez. Deployment of both skimmers will be required to demonstrate the full operability of the units.

<u>VOSS MV Sisuaq – Transrec Skimmer</u>

MV Sisuaq

Transrec 150 Skimmer

Transrec 150 Skimmer on Sisuaq

Transrec 150 Skimmer

Transrec 150 – Raising Skimmer Head

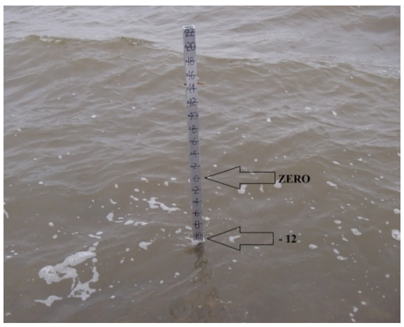
Transrec 150 – Raising Skimmer Head

In addition to verifying the presence of the two Transrec 150 skimmers, we had planned to require Shell to conduct a deployment drill with the equipment located on the Oil Spill Response Barge (OSRB) Endeavor. We were unable to gain access to the OSRB Endeavor because it was staged approximately 25 miles west of our location. Because drilling operations had not yet begun and because of the whaling ban there was currently no crew aboard and the equipment had not as yet been unpacked from the transit from Valdez.

<u>Task Force 7 Equipment Inspection - Wainwright, Alaska</u>

Task Force 7 equipment is staged in Wainwright, Alaska and is used for shoreline and near shore response operations. I contacted the site manager Hershel Frantz at 0930 prior to our departure from Barrow, Alaska notifying him that we would be arriving within an hour to conduct an inspection of the equipment staged at that location. We arrived at the Shell office at approximately 1030. We were provided a safety and orientation briefing prior to being taken to the equipment yard where the oil spill response assets are stored.

Upon arrival at the site it was explained to us that because of the wind and weather conditions they were unable to launch the vessels to conduct deployment exercises. Mr. Frantz explained that when the water level in the lagoon drops below a certain level they are unable to launch the boats without damaging them. They have installed a water level gauge on the beach they launch the boats from that marks the water level. The zero mark is the lowest water level at which they can launch the vessels from that location and the water level on the day we arrived was approximately 12 inches below that mark.



Water Level Gauge in Lagoon


Alternate Boat Launch


Anchors for Lagoon Mooring Area

It was further explained that to remedy this situation in the coming season, Shell would establish a mooring area in the lagoon and keep the vessels there until the end of the drilling season so they could be readily accessed by a skiff when needed. I asked if they had an alternate location from which to launch the boats and he indicated they had one on the ocean side but given the deteriorating weather conditions and increasing wave heights they didn't feel it safe to conduct operations unless it were an emergency situation.

All equipment listed in the inventory permanently staged for Task Force 7 was present and in operational order. All equipment readily started and appeared to be good condition. Six additional boats are identified to support Task Force 7 but these vessels are located in Prudhoe Bay and would be transported to Wainwright in the event of a spill. Vessel types and condition are described under the Prudhoe Bay inspection section above.

<u>Vessels - Landing Craft 4 each</u>

Seahorse Island

Neakok Island


Vessel Controls


All Vessels - Twin Outboard Motors


Vessel Engines

Doctor Island

Crescent Island

Spare Engine for Vessels

Tractor for Launching Vessels

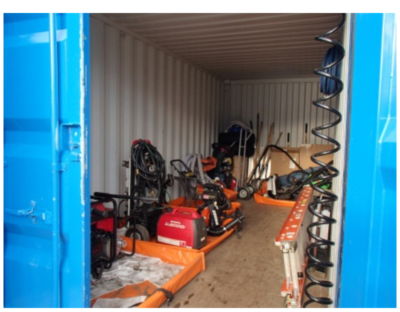
Conventional Boom - 10,000’

Coastal Boom – 4,000’ and Inflators

Coastal Boom on Reel

Power Pack for Boom Inflator

Inflator Control Panel

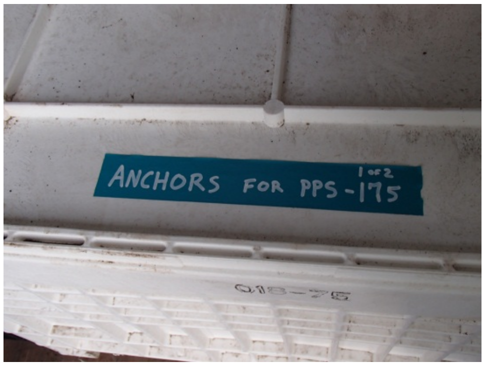


Equipment Storage Connex

Preparing to Start Handheld Boom Inflators

Shoreline Guardian Boom - 4,000'

Following the equipment inspection we returned to the Shell office and I reviewed the most recent inspection and maintenance records for September. The records are forwarded to Anchorage for storage and entered into the equipment management database to track required inspections and preventive maintenance. We were also shown how Shell is improving their response operations by visiting each priority protection site (PPS) in the area and making detailed surveys of the sites to improve the response tactics. These surveys included recording the current coastline configuration, measuring water depths and tracking currents. From these surveys response equipment packs are specifically designed for each PPS to ensure more effective site protection.



Site Specific PPS Equipment Packs

Anchors, Lines and Floats for PPS 175

Equipment Inspection - Chukchi Sea

We met daily from September 26 – 28, with the Shell representative in Barrow to coordinate our visit to the vessels in the Chukchi. Our intention was to travel out to the Chukchi drill site on September 27 but we were unable to transit out to the MV Fennica because our USCG transportation was involved in a search and rescue mission in the region and due to extreme weather conditions at the drill site. Seas were running at wave heights from 10 – 12 feet with occasional waves to 17 feet and the forecast had conditions above response operational limits through Saturday. Shell had suspended all personnel transfers via helicopter and the weather and wave conditions precluded any vessel to vessel transfers or equipment deployment.

On September 28, the USCG indicated that we could possibly go out and they could lower us onto the MV Fennica but that was of limited value because none of the equipment we needed to inspect was located on that vessel and conditions would not allow for vessel to vessel transfers or equipment deployment. It was decided to cancel the Chukchi inspection until a later date.

During our time in Barrow, we did verify the presence of Task Force 3, the Oil Storage Tanker Affinity and the other vessels identified for oil spill response for the Chukchi Sea via the Marine Exchange Vessel Tracking System (VTS). This system shows the location of vessels transmitting position data to VTS satellite.

All response equipment identified to support oil spill response requirements for the Chukchi Sea OSRP was inspected in May while in Valdez. At that time all equipment, except for the port side LSC-5 Brush Skimmer which was undergoing a manufacturer's modification to improve durability, was operational and in good condition.

Lessons Learned

These inspections and drills were intended to be carried out in July when Shell had anticipated initiating their exploratory drilling operations. Multiple delays caused by the presence and persistence of ice in the Chukchi Sea, equipment problems, and the extended whaling ban in the Beaufort Sea all caused Shell's operations to commence later in the season than planned, further limiting our ability to access the areas and conduct inspections and deployment drills. Whaling season is usually completed before late September which is why we had planned our inspection at this time. Due to the death of an elder in one of the villages, whaling was stopped until after the funeral which in turn kept drilling operations on hold.

It is highly unlikely that OSRD will be able to conduct truly unannounced inspections of the Shell OCS exploration operations due to the logistical constraints with air access and the need to conduct vessel to vessel transfers to inspect equipment or initiate drills. Because of the limited access to helicopter support and the need for those aircraft to coordinate operations with the vessels in advance of landing or depositing personnel, future inspections need to be scheduled with Shell and their helicopters should be used to access the offshore equipment.

Inspections should be conducted for just one site at a time instead of all at once to allow for delays in accessing offshore locations due to potential weather conditions. Fog, high winds and waves routinely plague these areas and as was just demonstrated, shut down opportunities to access the vessels and to have them deploy the equipment.

Another critical limiting factor in conducting inspections is the limited availability of hotel accommodations for the inspection staff in both Prudhoe Bay and especially Barrow. Only because the USCG had space available in Barrow, were we able to conduct the inspections in Wainwright and await transportation to the offshore site in the Chukchi. If the USCG continues to conduct seasonal operations in Barrow, BSEE should establish an agreement with the USCG to allow us access to any available rooms they may have reserved. If rooms are not available then it may become necessary to request housing at the Shell facilities in Barrow or on the Shell vessels assuming transportation out to the site is possible.

Sensitivity Information

PRIORITY PROTECTION SITES

SITE NO.	DESCRIPTION	SENSITIVITY	TACTIC	EST. BOOM
PS175	Break in the barrier island leading into Wainwright Inlet.	Most sensitive during open water season. Prevent oil from entering the inlet.	C-13 or C-14	800'
PS176	Break in narrow strip of beach fronting a small enclosed lagoon.	Most sensitive during open water season. Winds increase the odds of a breach. Prevent oil from entering the lagoon.	C-14	200'
PS177	Break in narrow strip of beach fronting a small coastal lake fed by a creek.	Most sensitive during open water season. Winds increase the odds of a breach. Prevent oil from entering the lake.	C-14	100'
PS178	Break in narrow strip of beach fronting a small enclosed lagoon.	Most sensitive during open water season. Winds increase the odds of a breach. Prevent oil from entering the lagoon.	C-14	100'
PS179	Break in narrow strip of beach fronting a small enclosed lagoon.	Most sensitive during open water season. Winds increase the odds of a breach. Prevent oil from entering the lagoon.	C-14	100'

GENERAL SENSITIVITIES

- All activities within the National Petroleum Reserve – Alaska (NPRA).
- Coastal areas support high concentrations of breeding, nesting, brood-rearing, and molting waterfowl, diving, shore and sea birds during the open water months (generally Apr-Oct). Expect to deploy bird hazing systems.
- Wainwright Inlet has high populations of migrating waterfowl, Jul-Aug.
- Walrus may be present off shore on ice floes, Mar-Nov.
- Bearded Seals may be present in coastal waters and/or on ice, Jan-Dec.
- Ringed Seal breeding and pupping along shorefast ice, Jun-Feb.
- Spotted Seal concentrations can be found in the Kuk River and Wainwright Inlet, Jul-Nov.
- Bowhead Whales (endangered species) migrate to the Arctic Ocean and may be present, Mar-Jun.
- Beluga Whales present in Chukchi Sea and Wainwright Bay, Jun-Jul, providing subsistence hunting opportunities.
- Gray Whales may be present in Chukchi Sea, Jun-Sep.
- Freshwater rivers and many inland lakes contain resident and anadromous fish species.
- Chinook Salmon may be present in Chukchi Sea/coastal waters, Jun-Sep.

CULTURAL SITES

The location of known cultural resource sites in this area is confidential and thus not shown on the accompanying map. This information is instead contained in a secure, online database accessible through the State Historical Preservation Office (SHPO) at (907) 269-8721. Planners, responsible parties and response teams should consult SHPO directly to acquire the latest, updated information on known cultural sites in the area.

Additionally, responsible parties and response teams should be particularly attentive to the possible existence of previously-unknown cultural resource sites at/on coastal barrier islands, elevated terraces or cut-bank bluffs along rivers, pingos, most shoreline areas (particularly near embayments or promontories), and prominent inland hills.

NOTE: All values given on these pages are for planning purposes only.

Response Considerations

AIR ACCESS*

- An unattended, 4,500 ft. gravel airstrip serves the village of Wainwright. Visual inspection recommended prior to use.
- Wainwright Air Station is closed to the public and should be considered for emergency landing only. The unattended, 3,000 ft. gravel runway is not maintained and its condition is unknown. Visual inspection recommended prior to use. May be used for spill response operations upon approval by Elmendorf Air Force Base, 11th Air Force Airfield Management, (907) 552-7384/3636/5265.
- An unattended, 4,400 ft. gravel airstrip serving the village of Atqasuk (located out of map coverage area) is located approximately 62 miles east-southeast of the village of Wainwright. Visual inspection recommended prior to use.

VESSEL ACCESS* AND HYDROGRAPHIC CONDITIONS

- Entrance to Wainwright Inlet is a narrow, winding channel between Point Collie and Point Marsh. It's depth is approximately 6 ft. and is deep enough to accomodate barge traffic, but passage should not be attempted without the aid of local guides and/or pilots.
- Shoals extend approximately 0.7 miles off the inlet, and are well-defined by breakers during moderate weather. During west storms, the breakers stretch across the channel.
- Current through the inlet may reach a maximum velocity of 2 knots.
- Chukchi Sea currents near shore flow north at not less than 1 knot when unopposed by wind or stopped by ice. If the ice is open from shore all the way to Point Barrow, the funneling effect it creates increases current velocity to 2-3 knots near Point Barrow.
- Pack ice in this area breaks off from the shore ice in May, moving off and closing back in again with changing winds, until gradually moving off to the north and west. Young ice forms in the vacated spaces, but gradually gets thinner until it disappears in late June. Average freeze up in this area occurs around the first of October.

COUNTERMEASURES CONSIDERATIONS

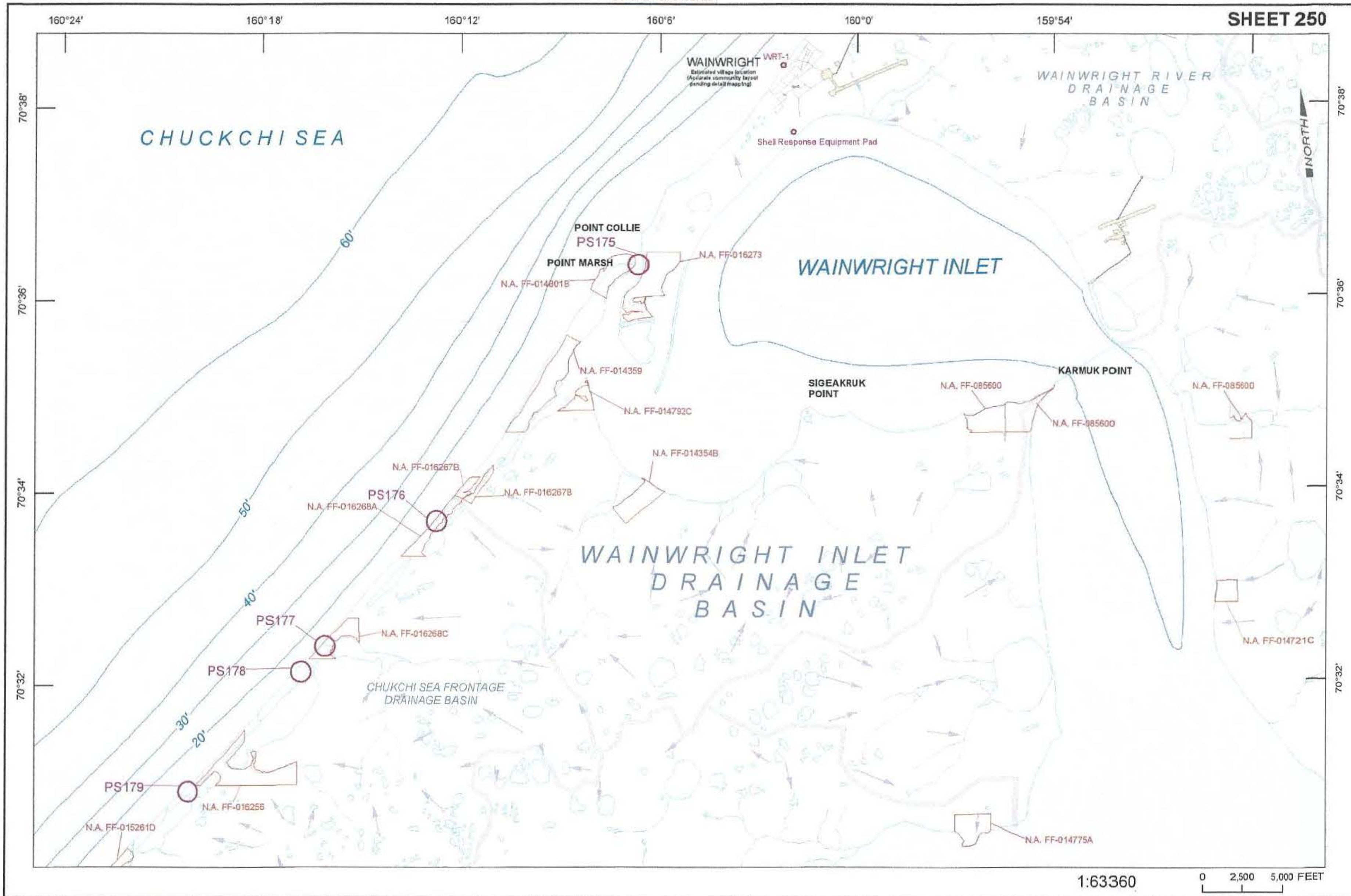
- Terrain is low with sandy beaches.
- Waterbirds will occupy leads in the ice during spring breakup.

*See the latest *Supplement, Alaska* and *United States Coast Pilot* for current information on air and vessel access, respectively.

NOTE: All values given on these pages are for planning purposes only.

ATTACHMENT 1

Continue on sheet 251



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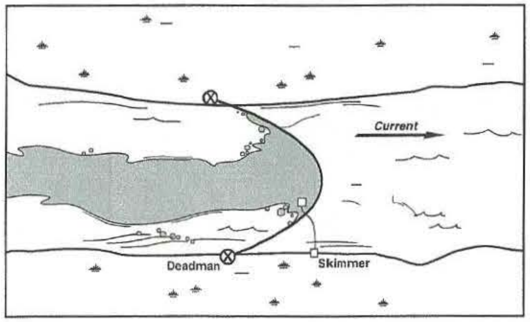
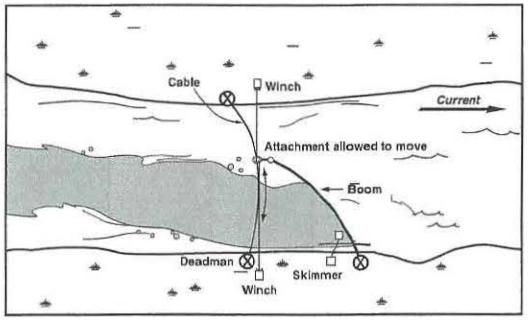
CATENARY



DEFLECTION/TROLLEY



Catenary (currents less than 1/4 knot): The boom is attached to an anchor on one bank, and the other end is towed to the other bank and attached to an anchor there. The current naturally puts the boom in a "U" shape ("catenary"). The deployment and maintenance of a single long boom can be difficult and labor-intensive. It is usually used for recovery operations.

Trolley (cable-supported diversionary boom): A cable or line is strung across a river and the boom attached to the trolley line with a pulley.

NOTE: *"Base Location" is storage location (may change seasonally); "Mobe Time" is time to get it out of storage, prepare it for operation, and make it ready to travel (concurrent for all equipment); "Deploy Time" is time to make it operational for its intended use at the spill site. These times do not include travel time from base to spill site, which may have multiple components (see Tactic L-3).*

EQUIPMENT AND PERSONNEL

- Select vessels and boom according to area, water depth restrictions, and function (see Tactic L-6). Specific personnel requirements depend on the length and type of boom and the nature of the area.

EQUIPMENT	BASE LOCATION	FUNCTION	PIECES	# STAFF PER SHIFT	MOBE TIME	DEPLOY TIME
Boom	All	Deflection booming	≥50 ft	6 for setup 3 to maintain	1 hr	3 hr
Work Boat	All	Booming support	2		1 hr	
Chain Saw Winch	KRU, GPB, Alpine	Booming support	2	4 for setup*	1 hr	
Anchor System	All	Anchoring boom	Variable		1 hr	
Floating Winch	ACS, EOA, Alyeska	Boom support	2		1 hr	

TOTAL STAFF FOR SETUP 10

TOTAL STAFF TO SUSTAIN OPERATIONS 3

**Recovery crews will maintain anchors and winches (see Tactic R-16).*

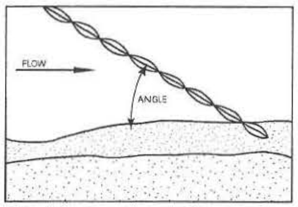
SUPPORT

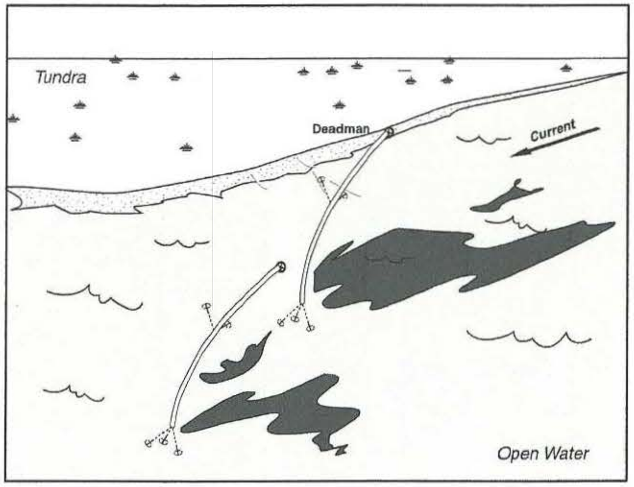
EQUIPMENT	BASE LOCATION	FUNCTION	PIECES	# STAFF PER SHIFT	MOBE TIME	DEPLOY TIME
Avgas Trailer	ACS, GPB, KRU, Badami, Alpine	Airboat fuel	1	1 (initial)	1 hr	0.5 hr
Mechanic Support	All	Support equipment	1	1	1 hr	0.5 hr

DEPLOYMENT CONSIDERATIONS AND LIMITATIONS

- 8x6 Delta boom is most commonly used for this tactic.
- Since the speed of the current perpendicular to the boom must be maintained at 3/4 kt or less, the length of boom needed to stretch across a stream depends on the current. For a stream 100 ft across with a 1 kt current, a boom approximately 140 ft long is needed. If the current is 2 kt, the same stream would require 320 ft of boom. The speed of the current is not equal across the stream; the fastest water is with the deepest water. Oil moving in a stream will be entrained in the fastest water.
- A cable extended across the river can be dangerous. Make sure everyone knows it's there and that any approaching boats are warned. Mark the cable with buoys.
- The shortest length of boom available is 50 ft. Generally, the minimum length required to boom a river such as the Sagavanirktok or Kuparuk is 500 ft.
- Readjust angles and widths between boom sections as current and wind change. Constantly monitor nearshore boom systems to prevent escape of oil.
- Approval from the Operations Section Chief is required for any vehicle tundra travel (off-road or off-pad), which must be in accordance with ACS' emergency tundra travel permit (See Tactic A-3). Any excavations in tundra or any tundra damage must be reported to the Operations Section Chief. All on-tundra activity must be documented and reported to the Planning Section for reporting to ensure permit compliance. Avoid archeological sites and biologically sensitive habitats. Travel across tundra with tracked vehicles, heavy equipment, and even foot traffic can seriously damage the vegetative mat, induce thermokarst, and cause structure disturbance. Using sheets of plywood as a traveling surface and minimizing trips with equipment greatly reduce disturbance of the tundra.

CURRENT (knots)	CURRENT (ft/second)	BOOM ANGLE RELATIVE TO CURRENT REQUIRED TO KEEP COMPONENT OF CURRENT <3/4 KNOT
1.5	2.5	30° to 42°
1.75	2.9	25° to 35°
2.0	3.4	22° to 30°
2.25	3.8	19° to 26°
2.5	4.2	17° to 24°
2.75	4.6	16° to 21°
3.0	5.0	15° to 19°





Deflection booming is often used where the water current is greater than 1 knot or where exclusion boom does not protect the shoreline. Deflection booming diverts oil to locations that are less sensitive or more suitable for recovery.

Boom is anchored at one end at the shoreline, while the free end is held at an angle by an anchor system. Deflection boom is deployed at an angle to the current to reduce and divert surface flow. This allows the oil to move along the boom and eliminates vortexes and entrainment. Anchoring is usually placed every 50 feet depending on the current. Anchoring distance will vary depending on current.

Cascading deflection boom involves two or more lengths of boom ranging from 100 feet to 500 feet placed in a cascading formation in the water. The lead boom deflects the slick, and subsequent booms placed downstream of the lead boom continue the deflection process until the slick is directed to the desired area.

EQUIPMENT AND PERSONNEL

- To determine the approximate length of boom required, multiply 1.5 times the length of shoreline to be protected. Select vessels and booms according to area, water depth restrictions, and function (see Tactic L-6). Specific personnel requirements depend on the length and type of boom and the nature of the area.

EQUIPMENT	BASE LOCATION	FUNCTION	PIECES	# STAFF PER SHIFT	MOBE TIME	DEPLOY TIME
Work Boat	All	Deploy deflection boom	2	6	1 hr	3 hr
Boom	All	Deflection	Variable		1 hr	
Anchor System	All	Anchor boom	Variable	2	1 hr	
Onshore Anchors (e.g., deadmen)	All	Anchor boom	Variable	—	1 hr	

TOTAL STAFF FOR SETUP 8

TOTAL STAFF TO SUSTAIN OPERATIONS 3 (AND 1 BOAT)

NOTE: *"Base Location" is storage location (may change seasonally); "Mobe Time" is time to get it out of storage, prepare it for operation, and make it ready to travel (concurrent for all equipment); "Deploy Time" is time to make it operational for its intended use at the spill site. These times do not include travel time from base to spill site, which may have multiple components (see Tactic L-3).*

NOTE: *"Base Location" is storage location (may change seasonally); "Mobe Time" is time to get it out of storage, prepare it for operation, and make it ready to travel (concurrent for all equipment); "Deploy Time" is time to make it operational for its intended use at the spill site. These times do not include travel time from base to spill site, which may have multiple components (see Tactic L-3).*

SUPPORT

- Recovery systems are sometimes used in conjunction with deflection boom.

EQUIPMENT	BASE LOCATION	FUNCTION	PIECES	# STAFF PER SHIFT	MOBE TIME	DEPLOY TIME
Avgas Trailer	ACS, GPB, KRU, Badami, Alpine	Airboat fuel	1	1 (initial)	1 hr	0.5 hr

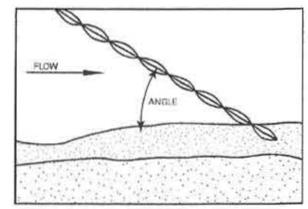
CAPACITIES FOR PLANNING

- One response team can deploy and tend up to 8,000 ft of boom in a 12-hour shift along 2 miles of shoreline (assumes 10 working hours in a 12-hour shift).

DEPLOYMENT CONSIDERATIONS AND LIMITATIONS

- The optimum angle of boom deployment depends on the current speed and the length and type of boom. The angle is smaller in strong currents than in weak currents and decreases as boom length increases. The more stable the boom is, the larger the optimum deployment angle is for a given current speed. Because deflection booms significantly reduce surface current, successive booms are deployed at increasingly larger angles.

CURRENT (knots)	CURRENT (ft/second)	BOOM ANGLE RELATIVE TO CURRENT REQUIRED TO KEEP COMPONENT OF CURRENT <3/4 KNOT
1.5	2.5	30° to 42°
1.75	2.9	25° to 35°
2.0	3.4	22° to 30°
2.25	3.8	19° to 26°
2.5	4.2	17° to 24°
2.75	4.6	16° to 21°
3.0	5.0	15° to 19°



- Don't assume 100% containment with one boom system.
- Readjust angles and widths between boom sections as current and wind change. Constantly monitor nearshore boom systems to prevent escape of oil.
- In extreme shallow water conditions, sheet metal may be used in lieu of boom in the apex. Use 36 pieces of metal and 37 stakes per 100 ft.
- Approval from the Operations Section Chief is required for any vehicle tundra travel (off-road or off-pad), which must be in accordance with ACS' emergency tundra travel permit (See Tactic A-3). Any excavations in tundra or any tundra damage must be reported to the Operations Section Chief. All on-tundra activity must be documented and reported to the Planning Section for reporting to ensure permit compliance. Avoid archeological sites and biologically sensitive habitats. Travel across tundra with tracked vehicles, heavy equipment, and even foot traffic can seriously damage the vegetative mat, induce thermokarst, and cause structure disturbance. Using sheets of plywood as a traveling surface and minimizing trips with equipment greatly reduce disturbance of the tundra.
- Below are boom towing limitations for airboats during overflood conditions in the nearshore Beaufort Sea (based on 2005 ACS seasonal recovery testing):

ICE CONDITIONS	FIRE BOOM (20 lb/linear ft)	FIRE BOOM (7 lb/linear ft)	FIRE BOOM (6 lb/linear ft)	DELTA BOOM
Groundfast or Shorefast Ice (with overflood)	100 ft	300 ft	350 ft	750 ft
Broken Ice: Large, Dense, First-Year, Afloat	100 ft	300 ft	350 ft	750 ft
Broken Ice: Smaller, Less Dense, Rotted	200 ft	600 ft	700 ft	1,000 ft

Memorandum for Record

June 19, 2012

To: David M. Moore, Chief, OSRD

Thru: Kelly Schnapp, Senior Advisor, OSRD

From: Christy Bohl, Senior Analyst, Alaska Region Unit, OSRD

Subject: Shell Equipment Inspection and Training Audit Report

On May 16 – 17, 2012 I conducted an inspection of Shell Offshore Inc. (Shell) oil spill response equipment currently staged in Valdez, Alaska and observed on-going training of oil spill response personnel that will conduct oil spill response operations in the Chukchi and Beaufort Seas during Shell's exploratory drilling operations tentatively scheduled to start in July 2012. Equipment inspections consisted of verifying the equipment was present and its physical and operational condition. Results of the equipment inspection and comments on the training are provided below.

Safety was a primary consideration during the course of the inspection. Upon arriving on each vessel I was provided a safety briefing which identified emergency notification signals, man overboard procedures, muster points in the event of an emergency, required personal protection equipment while on the vessel and potential safety hazards present on the vessel such as trip hazards, pinch points and areas of high noise. I was instructed that it was everyone's responsibility to bring activities to a halt if an unsafe situation occurred. Security procedures were also briefed for the oil spill response vessel (OSRV) Nanuq which consisted of restricted areas and the need for escorts while on-board.

Training:

Shell is conducting two, three-week training sessions for their personnel comprised of classroom, tiered/escalating on-water training, and on-water coordinated exercises and drills. I observed one day of the tiered on-water training and the first day of on-water coordinated exercises. On-water training involved instructing oil spill response technicians on the basics of the skimming equipment they would be using. The instructors covered how the equipment was assembled, started, and operated in both automatic and manual modes in the event the automatic mode failed during response activities so operations could continue.

Vessel captains also practiced skimming operations with containment boom towed in a "U" configuration with an open apex and 249 barrel (bbl) mini-barge secured to the aft section of the 47 foot skimming boat. This was to ensure coordinated activities between the vessels towing the boom and the vessel conducting skimming operations at the open apex. The on-water coordinated exercises involved deployment of all three large vessels and six of the workboats. They deployed skimming systems and practiced response operations.

The first lesson for each skimming system was focused on safety. The instructor identified the safety hazards associated with each piece of equipment and instructed the personnel on the correct operating procedures. When one of the safety protocols was violated the instructor stopped his presentation, corrected the individual and then resumed instruction. Prior to starting any machinery the operator ensured that required personal protective equipment was in place for all participants and observers. Also before any of the systems were put into operation the supervisor conducted a meeting spelling out what activities were going to be accomplished, who would be doing what, and stressing that anyone could bring operations to a halt if unsafe actions were observed. During and following operations of the equipment the instructors mentored the spill techs on the intricacies of the piece of equipment being operated and best practices to ensure smooth operations.

Both trainers and trainees were highly engaged in the training process. Instructors would quiz students on the systems to ensure that they were comfortable with all aspects of its operations. Each spill technician is required to demonstrate a level of proficiency for each task they will be required to carry out during a response operation.

Equipment Inspections:

Shell currently has three of its oil spill response vessels staged in Valdez, prior to deployment of these assets to the Beaufort and Chukchi Seas. The equipment inspected was identified from the Chukchi Sea Regional Exploration Program Oil Spill Response Plan and the Beaufort Sea Regional Exploration Program Oil Spill Response Plan. All equipment staged on the vessels in Valdez is in excellent condition and operational, except where noted in the report. The equipment in this report is presented by each vessel it is stationed on.

The personnel are keenly aware of the potential for releases of hydraulic fluid from the various pieces of equipment they work with. All hydraulic hose connections running across the deck have drip pans placed beneath them and sorbent pads are placed around connections and at the base of control panels to capture any potential leaks. Each fitting is wiped down before and after use to ensure that there is no residual fluid on the item and all ends are capped both on the control unit and on the hoses.

During the deployment of the Lamor LSC-5 skimmers on the oil spill response barge (OSRB) Endeavor the Shell representative stated that they were having a problem getting the metal drum at the end of the containment boom aligned with the boom arm and making the connection. They welded a plate on the top of the drum that allowed them to attach a lanyard to the drum and guide the two parts together. The Shell representative indicated that by making that adjustment to the equipment they had reduced their deployment of the system by nearly 45 minutes. Shell notified Lamor of this modification to help improve the product for future users.

As noted below one of the Lamor LSC-5 skimmers was not available for operational tests because it was being fitted with manufacture's upgrades to improve the durability of the units. For most users the skimmers are only deployed once or twice a year unless there is an actual event. Because of Shell's high level of practice in deploying and operating the systems the manufacturer reinforced sections of the skimmers to withstand the higher level of use and wear.

The remainder of Shell's oil spill equipment inspections will be conducted when the rest of the Shell oil spill response vessels are in-place either in either the Beaufort or Chukchi Sea. Shore-based equipment will be inspected during the inspection of Shell's oil spill removal organization Alaska Clean Seas (ACS) equipment.

Shell Oil Spill Response Assets for Chukchi and Beaufort Seas				
Unit/Inventory	**Quantity**	**Condition**	**Operational Status**	**Date Inspected**
		Task Force 1 - Chukchi Sea		
OSRV Nanuq	1	Excellent	Yes	5/16/2012
Work Boat, 34’	3	Excellent	Yes	5/16/2012
Lamor LSC-5 Brush Skimming Package	2	Excellent	1 – Yes 1 – No (Installing mfg upgrade modifications)	5/16/2012 5/17/2012
Vikoma Duplex Brush Skimmer	1	Excellent	Yes	5/17/2012
Ocean Boom	2600’	Excellent	Yes	5/17/2012
Fire Boom	500’	Excellent	Yes	5/17/2102
Dispersant Application System	2	Excellent	Unknown – require deployment at later date	5/17/2012
Vertical Rope Mop Skimmer	1	Excellent	Yes	5/17/2012
		Task Force 2 - Chukchi Sea		
OSRB Klamath/tug	1	Excellent	Yes	5/17/2012
Transrec 150 Umbilical Weir Skimmer	2	Excellent	Yes	5/16/2012
		Task Force 3 – Beaufort Sea		
Oil Storage Tanker	1	Unknown	To be inspected	TBD
		Task Force 4 – Beaufort Sea		
Vessel of Opportunity Skimming System (VOSS)	1	Unknown	To be inspected	TBD
Transrec 150 Umbilical Weir Skimmer	1	Unknown	To be Inspected	TBD
		Task Force 5 - Beaufort Sea		
VOSS	1	Unknown	To be inspected	TBD
Transrec 150 Umbilical Weir Skimmer	1	Unknown	To be inspected	TBD

Task Force 6 – Beaufort Sea				
OSRB Endeavor Tug	1	Excellent	Yes	5/17/2012
Lamor LSC-5 Brush Skimming Package	2	Excellent	Yes	5/17/2012
Workboat, 34’	3	Excellent	Yes	5/17/2012
Response Vessel, 47’	1	Excellent	Yes	5/17/2012
Lamor LORS-2C Brush Skimming Package	2	Excellent	Yes	5/16/2012
Duplex Mini-Brush/Disc Portable Skimmer	1	Excellent	Yes	5/17/2012
Coastal Boom	6,000’	Excellent	Yes	5/17/2012
Vertical Rope Mop Skimmer	1	Excellent	Yes	5/17/2012
100-bbl Flexible Containment System	1	Excellent	Yes	5/16/2012
249-bbl Interim Storage Mini-Barge	4	Excellent	Yes	5/16/2012
Ocean Boom	2600’	Excellent	Yes	5/16/2012
Fire Boom Systems	500’	Excellent	Unknown – require deployment at later date	5/16/2012
Task Force 7 – Wainwright				
Conventional Boom	10,000’	Unknown	To be inspected	TBD
Coastal Boom	4,000’	Unknown	To be inspected	TBD
Shoreline Guardian Boom	4,000’	Unknown	To be inspected	TBD
Landing Craft, 26’ – 32’	4	Unknown	To be inspected	TBD
Workboat	6	Unknown	To be inspected	TBD
Task Force 8 – Deadhorse				
Oleophilic Skimmers	20	Unknown	To be inspected	TBD
Storage Bladders (500 – 2,640 gal)	36	Unknown	To be inspected	TBD
Portable Folding Tank (2,500 gal)	50	Unknown	To be inspected	TBD
IMO Tank (6,000)	1	Unknown	To be inspected	TBD

<u>Oil Spill Response Vessel (OSRV) Nanuq</u>

Vessel is in excellent condition and fully operational.

<u>Work Boats 34' – 3 each</u>

Vessels are in excellent condition and fully operational. Two of the vessels were deployed and conducting on-water operations during the inspection period. One vessel was staged on the deck of the OSRV Nanuq. The vessel's engines were started to demonstrate that it was available for immediate deployment.

<u>Ocean Boom</u>

Containment Boom Inflator

Containment Boom Being Towed

Containment Boom being deployed from OSRV Nanuq

Ocean boom aboard the Nanuq had been deployed prior to me arriving on-board the vessel. I saw the boom being towed in an open apex U configuration as the vessel operators practiced on-water operations on May 16 and then witnessed the boom being deployed from the Nanuq on the morning of May 17 (see photos above). All sections of boom were inflated and appeared to be in good condition.

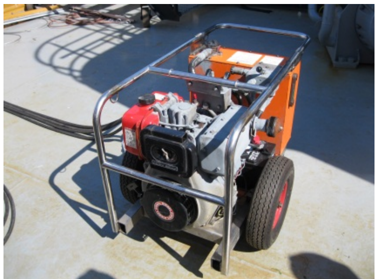
<u>Vertical Rope Mop</u>

Vertical Rope Mop

Skimmer Operations Test

The vertical rope mop is in excellent condition and fully operational. All hoses and fittings are in excellent condtion.

Vikoma Duplex Mini-Brush/Disc Skimmer



Vikoma Power Pack

Vikoma Brush Skimmer Head

Assembled Vikoma Skimmer

The Vikoma Mini-Brush/Disc Skimmer is in excellent condition and fully operational. All fittings and hoses are in excellent conditon.

Lamor LSC-5 Brush Skimmers

Starboard Side Skimmer

Boom Arm LSC-5 Brush Skimmer

LSC-5 Power Pack

Deployed LSC-5 Skimmer


Deployed LSC-5 Skimmer on OSRV Nanuq

The Lamor LSC-5 Brush skimmers are in excellent condition. I was able to verify that the starboard system is fully operational. All fittings and hoses are in excellent condition. The hydraulics package for the unit is available but not used. All skimming systems can be supported with the hydraulics system on the Nanuq.

The port side unit was being serviced to incorporate manufacturer modifications to enhance the durability of the unit and was unavailable for use. This unit will require reinspection and operational demonstration once the modification have been installed.

<u>Vessel Based Dispersant Application System</u>


Dispersant System Compressor


Dispersant Spray Arms

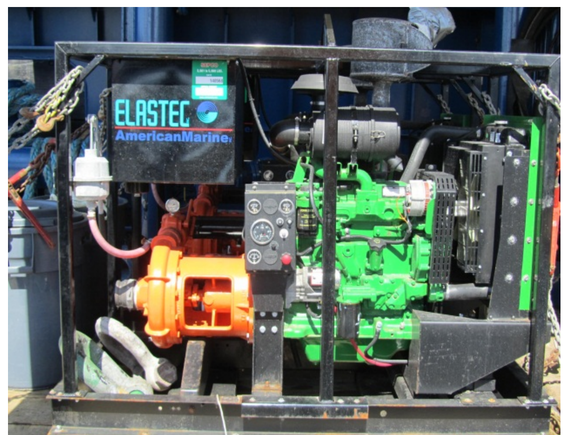
The vessel based dispersant application system is present on the Nanuq. The system appears to be in excellent condition but was not assembled or deployed during my visit. Shell had not started their training on this system. This unit will require reinspection and operational demonstration.

Fire Boom System

Fire Boom

Training Fire Boom

Fire Boom Power Pack

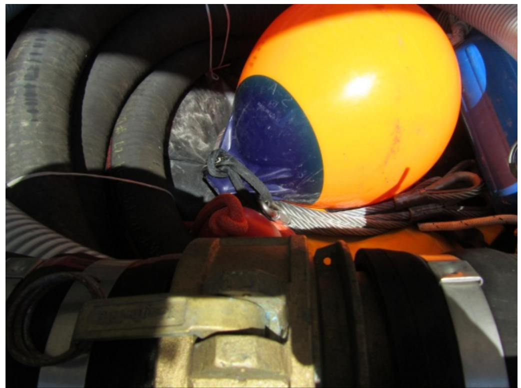


Fire Boom Power Pack

The water-cooled fire boom is presesnt and appears to be in excellent condition. The fire boom is not normally deployed because the exterior cover can be damaged. Shell has a reel of training fire boom available with which to practice deployment and operation with the power pack unit. This equipment will require reinspection and deployment of the practice boom.

Storage Bladder, 100 bbl

Storage Bladder



Hoses and Floats

The system is available and appears to in excellent conditons. All fittings and hoses are in excellent condition. The bladder was not removed from the crate.

Oil Spill Response Barge (OSRB) Klamath and Guardsman Tug

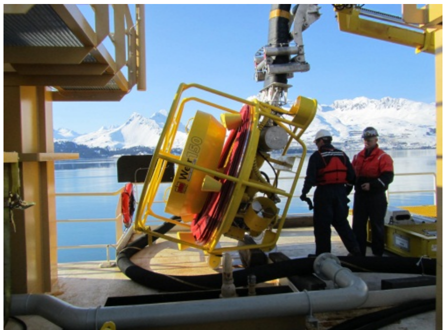
OSRB Klamath

Guardsman Tug

The OSRB Klamath and Guardsman Tug are in excellent condition and fully operational. The vessel was deployed and conducted skimming operations using the Transrec skimming units on May 17.

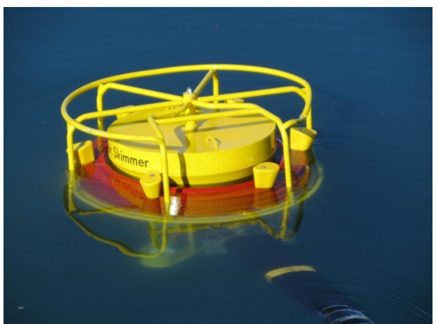
Transrec Skimming Unit – 2 each

Starboard Side Skimmer


Skimmer Head

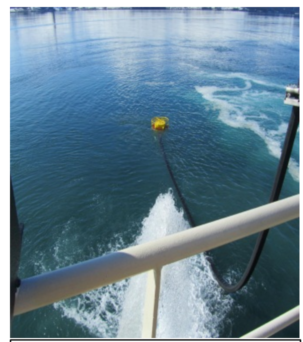

Hose Reel


Skimmer Head



Skimmer Head Deployed


Skimmer Manual Controls

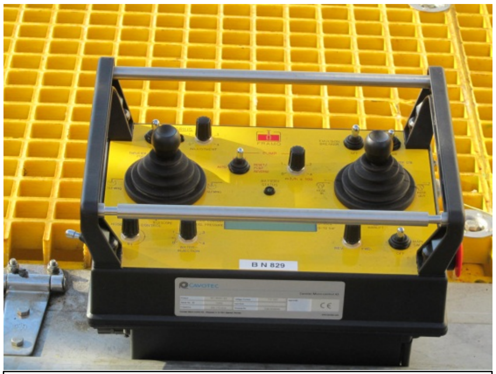

Active Skimming

The starboard Transrec 150 is in excellent condtion and fully operational. The system was deployed from the vessel in port on May 16 and then at sea during the deployment exercise on May 17.

Port Side Skimmer


Hose Reel


Skimmer Power Pack



Remote Controller

Skimmer Deployed

Skimmer Head

Skimmer Discharge

The port Transrec 150 is in excellent condition and fully operational. The system was deployed from the vessel in port on May 16 and then at sea during a deployment exercise on May 17. The skimmers were operated the majority of the day on May 17.

<u>Oil Spill Response Barge (OSRB) Endeavor and Pt. Oliktok Tug</u>

The OSRB Endeavor and Point Oliktok Tug are in excellent condition and fully operational. The vessel was deployed on May 17 and conducted skimming operations using the Lamor LSC-5 skimming units.

<u>Work Boats 34' - 3 each</u>

Vessels are in excellent condition and fully operational. Vessels were deployed and operating the entire duration of the inspection.

<u>Work Boat 47'</u>

The vessel is in excellent condition and fully operational. This vessel has a Lamor LSC-2 brush skimmer incorporated into the hull and is used as the skimmer in the open apex of a U boom configuration.

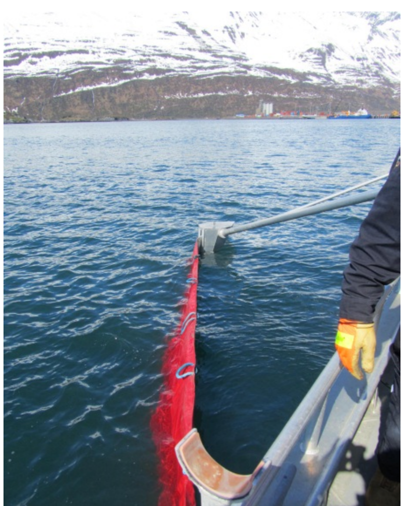
Lamor LORS-2 Skimmer

LORS-2 Brush Skimmer

LORS-2 Brush Skimmer System on 47' Workboat Arctic Skimmer 1

LORS-2 Skimmer System Controls

LORS-2 Boom Arm Deployment



LORS-2 Port Boom Arm

LORS-2 Starboard Boom Arm

The Lamor LORS-2 Brush Skimmer is in excellent condition and fully operational. The pumps in the hold were started to demonstrate their operability as well.

<u>Lamor LSC-5 Skimmers - 2 each</u>

<u>Starboard Side Skimmer</u>

LSC-5 Brush Skimmer

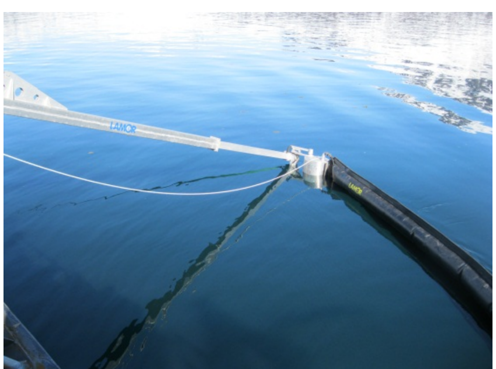

LSC-5 Skimmer Deployment

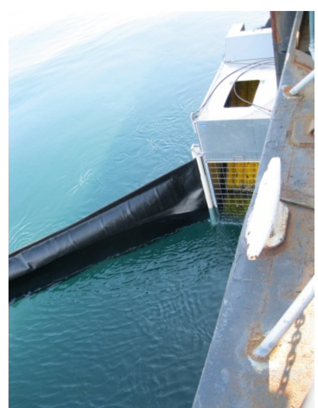

Skimmer Containment Boom


LSC-5 Power Pack


Assembling Power Pack


LSC-5 Control Panel


Skimmer Arm and Containment Boom


LSC-5 Deployed

The Lamor LSC-5 Brush Skimmer for the starboard side of the vessel is in excellent condition and fully operational. All hoses and connectors are in excellent condition.

Port Side Skimmer

Deploying LSC-5 Skimmer

Deploying LSC-5 Skimmer

Boom Float

Attaching Hydraulic Lines

LSC-5 Hydraulic Control Panel

LSC-5 Skimming Configuration

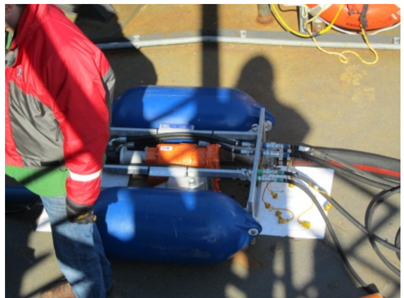
Boom Arm Extended, Boom Inflated

Skimmer Brushes

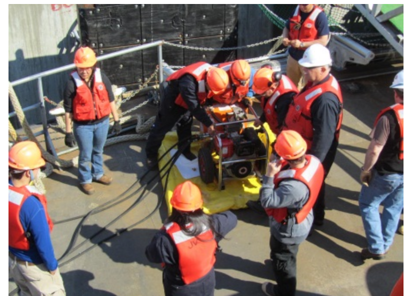
The Lamor LSC-5 Brush Skimmer for the port side of the vessel is in excellent condition and fully operational. All hoses and connectors were in excellent condition.

<u>Vikoma Duplex Mini-Brush/Disc Skimmer</u>

Disc Skimmer Head



Pump

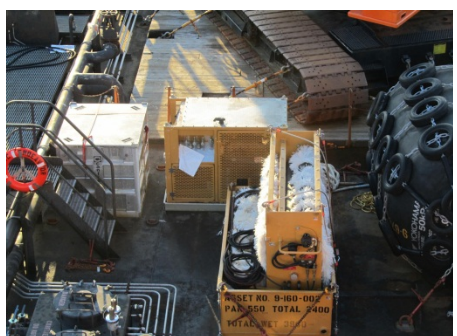


Training on Vikoma Skimmer Ops

The Vikoma Duplex Mini-Brush/Disc Skimmer is in excellent condition and fully operational. All hoses and connectors are in excellent condition.

<u>Vertical Rope Mop Skimmer</u>

Vertical Rope Mop Skimmer Power Pack



Rope Mop Skimmer and Power Pack

Skimmer Operation Test

The vertical rope mop skimmer is in excellent condition and fully operational. All hoses and connectors were in excellent condition.

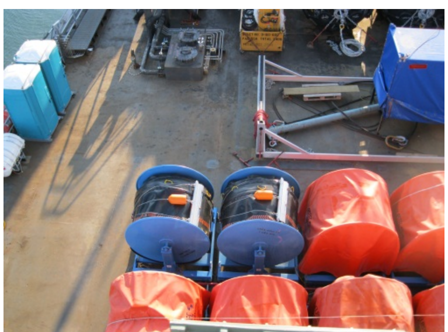
<u>Ocean Boom – 2,600’</u>

Ocean Boom on Storage Reel


Reels of Ocean Boom

The ocean boom is in excellent condition and the full quantity is present. The boom was not deployed during the visit.

<u>Coastal Boom – 6,000’</u>

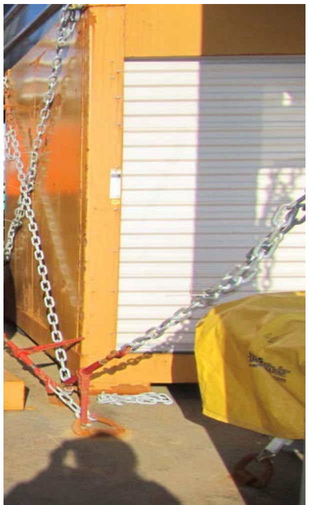

Coastal Boom on Storage Reels


Coastal Boom


Coastal Boom on Storage Reels

The coastal boom is in excellent condition and the full quantity is present. It was not deployed during this visit.

Fire Boom 500’

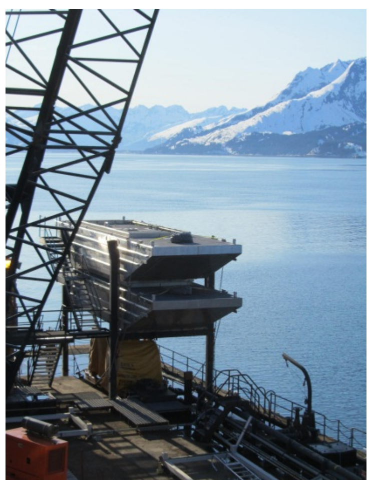

Fire Boom Storage Locker


Fire Boom on Storage Reel

The Elastec Fire Boom is in excellent condition and the entire volume is present. Note: The fire boom on the OSRB Endeavor was physically inspected but the photos were not accessible on the camera memory card. The photo on the left is the container of fire boom and pump systems physically located on the OSRB Endeavor. The boom in the photo on the right is from the OSRV Nanuq and is identical to the fire boom located on the OSRB Endeavor.

Mini-Barges, 249 bbl – 4 each


Two 249-bbl Storage Barges


Two 249-bbl Storage Barges


Top of 249-bbl Storage Barge

The 249 bbl mini-barges were in excellent condition and fully functional. The full quantity was on-baord. On May 16 one mini-barge had been deployed for use in the open apex U skimming exercise.

Superior Energy Services

Arctic Containment System (ACS)

Dome Deployment and Flow Test of Dome

March 20 through 23, 2013

Director Mark Fesmire and Chief Inspector Randy Howell arrived on the barge Arctic Challenger on March 20th at 10:10 am, and shortly thereafter received a briefing on deploying the Dome. This was immediately followed by a Job Safety Analysis (JSA) with everyone involved with the operation.

A target site was picked that was 366 feet from the barge. The ROV did a site bottom survey of the target site and this was completed by 12:33hrs March 20th. Started deploying clump weights, had 3 weights set when the winds increased above 25 knots and seas also increased to 6'. Superior stopped operations pursuant to established operational limits on the hoisting equipment.

March 21, once winds and sea state dropped to within Superior operational limits, Superior held a JSA and continued running clump weights. After completion of this operation, Superior held another JSA prior to beginning to deploy the Dome. Superior had the Dome near the target site at 19:00hrs and started attaching winch wires to clump weights. Had 3 wires attached and ROV was verifying one of the winches connection when an arm on the ROV bumped a hydraulic line, breaking the hydraulic line. ROV operator noticed the broken line right away and reported to control room operator who stopped operations and shut down hydraulics to the dome. Pull dome back to the barge and set dome back on the barge.

March 22, 12:20hrs dome back at the target site starting the attachment of winch wires to clump weights. ROV lost control of Joy Stick and had to retrieve ROV back to Barge for repair. It was a quick fix and the ROV was back in operation, had all winches attached to clump weights and the dome winched down to the 150' level at 19:30hrs. At 19:50hrs started the flow test of the dome. The dome has 2 pumps; each individual pump was test to 25%, 50%, 75%, and 100%. At 25% = 5,300 (Barrel Per Day) BPD rate, 50% = 17,000 BPD rate, 75% = 26,500 BPD rate, and 100% = 34,000 BPD rate.

Findings; The test of the Dome component of the Arctic Containment System went well. BSEE did not re-test the separation and treating system of the barge at this time, that test was completed in 2012.

Superior held JSA's at the start of each operation and at each crew change. The meetings covered the operations during that shift or operation. Superior also emphasized at every JSA that each employee had the authority to stop the operation any time they observed an unsafe condition.

Superior did have some minor issues, documented above, that involved the ROV. When a problem occurred, Superior stopped the operation, identified the problem, found a solution and worked according to the Operation Manual to complete the task. Their operation manual is a well written document that contains a step by step procedure and checklist for each operation. The Containment Dome operated as designed and the lifting capacity of each of the two pumps in the system exceeded the expected worst case discharge (25,000 barrels per day) of a well blow out in the Chukchi Sea

Arctic Containment System Corrective Actions from September 2012 test.

1. Winch Hook Design: one of the winch hook safety hooks was damaged during prior test.
   Action taken: all 8 of winch hooks have been changed from 5 ton to 22 ton rating with a beefier safety latch.
2. Saddle Clamp Termination for winch hooks: one of the saddle clamp terminations slip during prior test.
   Action taken: change out all 8 saddle clamps termination for a potted connections.
3. Tension Instrument Communications: the load cells on the winches were shorted out by sea water.
   Action taken: all connections were replaced and all of the wires and connections were hyperbarically tested at 5 times the expected seawater pressure during deployment.
4. XV115 valve and ZI115 Position Indicator: the position indicator for valve XV115 was damaged by rigging when the dome surfaced. This resulted in valve not being able to respond to the close signal and water ingress into the control wiring for VX115.
   Action taken: Redesigned the dome. No active buoyancy is managed in the center chamber. Converted XV-115 and VX-104 A, B, and C (which are all vent valve for the center chamber) to be operated by ROV. Steel grating placed over top of the dome to protect valving and wiring.
5. Ingress Hole Size for Buoyancy Chamber A – D: the four outside buoyancy tanks had 3 lines each that were 1 ½" at the base of the buoyancy tanks and were not of sufficient size to allow the necessary rate of pressure equalization to prevent collapse of the buoyancy tanks.
   Action Taken: Vents were redesigned so that each tank has 2 vent s that are 14" diameter. The vent tubes were sized to limit the differential pressure to less than 7.5 psi
6. Winch Operation and Control System: one of the winches had more wire paid out than was last observed prior to the incident.
   Action Taken: the winch software was changed to require a confirmation of any pay-in or pay-out command prior to the initiation of the action to avoid inadvertent commands. In addition the auto-payout feature on the winches was disabled to eliminate the potential that it could lead to an unintended pay out of mooring lie.
7. Buoyancy Control: the measurement of buoyancy was dependent on winch line tension measurements and they were lost when the tension measurement of one load cell overloads the entire manifold instrument communication system. This condition resulted in the loss of communication to half of the dome winches (A-D or E-G).
   Action Taken: the electrical system for tension monitoring was modified so that a failure by any single load cell would not affect the other winch systems. The level measurement system for the buoyancy tanks was calibrated and the software modified to show actual levels verses

differential pressure, and a graphical tank level screen was added to the system to show tank levels in a visual display.

8. Buoyancy: the dome was heavier in water than the buoyancy provided by A – D chambers alone, but adding the center chamber for buoyancy they had significant excess buoyancy, enough to overcome clump weights.
   Action Taken: the Perimeter buoyancy tanks A-D were increased in size to provide a net buoyancy of 16 kips when all perimeter tanks are filled with nitrogen. This eliminates the need to use the center chamber as buoyancy.
9. Deployment Process: the original operational plan was to deploy the base of the dome to 70' alongside the barge, then move dome out near the target site and connect the clump weights, then use mooring winches to lower the dome down to 150'. This process required monitoring and several interventions to make sure that the dome maintained positive buoyancy as it was moved to a lower depth and the nitrogen was further compressed by the increase pressure.
   Action Taken: the procedure now is to lower the dome alongside barge to the finial depth. Then move the dome near the target site, and connect the mooring system to the clump weights. The dome is then made positive buoyant so that Oceanguard buoy can be disconnected, and final adjustments are made to position the dome over the plume.
10. Deployment Mooring Configuration: the 4 clump mooring configuration during the test essentially put most of the load across one diagonal axis / 2 clump weights. This created a situation where losing one could cause loss of control over the position of the dome.
    Action Taken: change the procedure to require all 8 clump weights to be deployed. A heavier set of 8 clump weight will be used and they will be weighed using a crane with a certified load cell and the weight will be recorded on each clump weight.

Design 1, Buoyancy Tank Stiffening: the perimeter ballast tanks were evaluated for a differential pressure of 10 psi to represent potential scenarios that are outside of the planned operating scenarios. The ballast tanks were then modified with reinforcing rings to resist these pressures.

Design 2 Reduce Venting for Unlevel Dome: The newly modified and greatly enlarged J-tubes vents were extended from the bottom of the perimeter buoyancy tanks to have an opening in the side of the dome, several feet below. Extending the vent tubes below the perimeter buoyancy tanks means that should the dome be unlevel , there will be only a small volume of nitrogen vented, resulting in greatly reduced adjustment to buoyancy.

Arctic Challenger

Flow test of containment system

8-27-2012

Director Mark Fesmire and I met with Shell representative at the docks in Bellingham to do an inspection and test of the arctic challenger flow process. The day started out by going over what the test would entail and how the test would be performed.

The test will be using fresh water in a closed system to test the flow of the liquid part of the flow process; the first vessel that the liquid flow to V-110 Surge vessel, then flow to V120 Production Separator, then finial stage V-200 Flare Feed Drum. Then the process is started over. There are two heat mediums and two pumps between vessels V-120 and V-200. One pump is for low flow and the second is for high flow rate.

The test started by having flow going from V-110 to V-120 then the low flow pump pushed the flow up to V200. The flow rate on just the low flow rate pump was a maximum of 15,000 BPD on the sonic meter which is down stream of V-200. Spoke to Shell about needing to verify that the process can handle liquid flow of at least 25,000 BPD the worst case discharge. Superior Operator turned on the high flow pumps and brought the pumps to maximum flow of 60,000 BPD, and a stable high flow rate of 50,000 BPD range.

We also verified Critical Equipment associated with the dome:

- Control Valve ZLB-102 Incoming Shut Down Valve (SDV), verify that valve closed when a Emergence Shut Down (ESD) is actuated.
- 8” Gas Hose, rated to 150 psi, length of hose 850’
- 6” Oil Hose, rated to 150 PSI, length of hose 850’

Verified that Shell had updated Safety Analysis and Safe Charts

- Drawing No. 2011-009-SF-001 sheet 2 of 4 and Safe Chart sheet 3: T-200 Glycol Expansion Tank is identified correctly as MBJ on both sheets.
- Drawing No. 2011-009-SF-001 Sheet 1 of 4, and Safe chart Sheet 2: V -120 missing SAC reference for PSL. PSL installed and operational, no SAC reference required now.
- Drawing No. 2011-009-SF-001 sheet 1 of 4 and Safe Chart sheet 2: T-100 CPI separator under upset conditions LSH did not shut down both pumps. Now T-100 LSH will shut down both pumps P-125 and P -120.

Equipment that we verified as part of the capping stack:

- Choke manifold
    - 2, Hydraulic Chokes
    - 1, Manual Choke

- Choke manifold rated to 10,000 psi, and reviewed test records of pressure test of the choke manifold. Test records showed tests of low 200 psi and high of 10,000 psi of all the pipe and valve that are upstream of the choke valve.
- 2 high pressure 3.5” hoses, rated to 10,000 psi, length of hose 807’, and both hoses tested to 15,000 psi at the factory.

The flow test of the containment system was successful.

Mark Fesmire

Randy Howell

The Deployment and Pressure test of Capping Stack

6-25-2012

Deployment of Capping Stack

Mark Fesmire and Randy Howell arrived at the Ice Breaker Fennica in Everett harbor, received a safety briefing, and a presentation on the Capping Stack deployment procedure.

Held a JSA with everyone involved in the operation

The Fennica moved out of Everett Harbor about 2 ½ miles, dropped a position locator to the sea floor. This locator was a backup to the GPS system to ensure the vessel remained at the intended location using the dynamic positioning of the vessel as if they were deploying the Capping Stack on to a flowing well.

Deployed the ROV to a depth of 100'prior to moving the stack over board. Moved stack over board and stopped at 100', ROV surveyed Capping Stack, continued lowering stack down to 200'. ROV surveyed stack again and inspected the ring gasket.

Pull stack back to the Fennica and set back on test stump/ shipping cradle.

All operation was performed as per the operational procedures.

6-26-2012

Pressure Test of Capping Stack

Reviewed testing procedures for the Capping Stack, (noticed that there wasn't a low test pressure) Shell / Wild Well Control said that they will add a low pressure test to the test. Also held a JSA prior to starting the pressure test.

The first test tested the lower pipe ram and the two outer sacrificial gate valves that can be changed out while in operation. The low pressure test was to 250 psi held for 5 minutes with no loss of pressure, then staged up the pressured to 10,000 psi held for 15 minutes with no loss of pressure.

The second test tested the upper pipe ram and the inner primary gate valves. Low pressure test to 250 psi held for 5 minutes with no loss of pressure, then staged up the pressured to 10,000 psi held for 15 minutes with no loss of pressure.

Stump testing of the Capping Stack was successful.

6-27-2012

Drilling Well On Paper Meeting (DWOP)

Mark Fesmire and Randy Howell attended Shell's DWOP meeting that included employees and contractors that will be involved in drilling the wells this summer (Drilling Engineers, Shell Company, Tool Pushers, Drillers, Mud Engineers, Mud Loggers, Cementers, Mud Line Cellar Engineers, etc.). There were approximately one hundred people attending. The majority of the people in this meeting were contractors and employees who will be on location this summer.

The meeting started out with an overview of Shells arctic proposed drilling program for this summer, then the facilitators started talking in general terms of the of drilling of the wells. The attendees were then broken up into groups by drilling rig Each rig specific group was then further broken into 4 smaller groups by functional responsibility ;(8 ½" pilot hole) (Mud line cellar) (Opening 8 ½" for 30", 20", and 13 3/8" casing) and (Drilling 12 ¼" hole for 9 5/8" casing and the open hole section to TD).

The procedures for each function where then walked through and each group discussed ideas for improved operational procedure and safety measures.