OCEAN ENERGY SAFETY ADVISORY COMMITTEE

January 25, 2013

Mr. James A. Watson
Director
Bureau of Safety and Environmental Enforcement
1849 C Street, N.W.
Washington, D.C. 20240

Dear Director Watson:

On behalf of the Ocean Energy Safety Advisory Committee (OESC), I would like to submit 20 recommendations to the Department of the Interior (DOI) and the Bureau of Safety and Environmental Enforcement (BSEE) for consideration and action. Over the course of the past two years, the six OESC subcommittees have been working hard to formulate and evaluate recommendations addressing each subcommittee topic for full Committee consideration. At our recent January 9-10, 2013, meeting in Washington, D.C., the OESC determined the 20 recommendations listed below ready for submission to DOI and BSEE. Additional information on these recommendations is provided in supplementary enclosures to this letter. Each enclosure has a label on the top left corner of the document highlighting the corresponding sections below. It is necessary to consider the recommendations in the context of its related supplementary enclosure.

Please accept these submissions as the OESC's formal recommendations to DOI/BSEE:

Spill Prevention (Reference material found in Enclosures 1-2)

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

  The JIP would:
  - Establish the ultimate goal of automated well safety systems
  - Establish a technology roadmap with a step-wise approach to the goal
  - Determine the gaps between existing projects and the need for additional work
  - Determine technology that should be adopted from other industries
  - Recommend appropriate parties for newly identified projects
  - Recommend an oversight and alignment mechanism to monitor and assure progress

  Participants in the JIP should include expertise from the following organizations:

- Government agencies such as BSEE, U.S. Coast Guard (USCG), U.S. Geological Survey (USGS), Department of Energy (DOE), and National Oceanic and Atmospheric Administration (NOAA)
- Industry companies from operators, equipment manufacturers, service companies and drilling contractors
- Academia
- National laboratories

Funding for the JIP would be derived from either Federal appropriations or revenue from Federal royalties, rents, and bonuses on Federal offshore oil and gas leases issued under the Outer Continental Shelf (OCS) Lands Act. In addition industry would provide "in-kind" and monetary contributions.

Monitoring/oversight of the JIP could be performed by the Offshore Energy Safety Institute (OESI) as recommended by the OESC.

- ***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. Specifically:***

BSEE, with input from OESI, would identify and prioritize the technologies, equipment and/or processes to consider based on OESI's work to identify safety-critical technology and regulatory gaps, and the results of investigations into offshore incidents.

For the chosen technologies, equipment and processes, industry standards organizations would develop testing protocols for establishing performance levels, failure points, and reliability. The criteria should be based on the operating environment in which the technology would be used.

OESI would facilitate forums that convene the relevant expertise to provide input to BSEE on BAST-related topics, including the suitability of test protocols, establishing performance standards based on test results, and analyses of the costs and benefits of applying relevant standards across the OCS.

These forums would recur on a regular basis to support the goal of an evergreen process. These forums could also be used to provide peer review to technology projects being carried out by other entities (e.g., oil and gas companies; manufacturers; research consortia), by reviewing testing and assurance data and advising on whether the technology is ready to be tested/used on the OCS.

Based on input from OESI and the expert forums, BSEE would decide whether to accept the testing protocols and evaluation criteria.

The critical technologies and equipment would be tested using BSEE-accepted protocols. Based on these tests, analyses of economic feasibility and input from the expert forums, OESI would recommend performance standards.

The OESI recommendations would also address, based on the economic feasibility analyses, whether the standard would apply prospectively only or would also apply to existing facilities.

BSEE would then adopt performance standards for BAST based on its consideration of these OESI recommendations. Operators would be required to meet BSEE-adopted performance standards.

If an OESI is not established or charged with implementing the BAST process, BSEE should develop other options for obtaining third party expertise to manage the BAST process.

- ***BSEE should revise its regulations at 30 CFR 250.107(c).***

  The revision would remove the language stating that complying with BSEE regulations constitutes compliance with the BAST requirement.

  The revised regulation would specify that technologies and equipment that are evaluated through the BAST process recommended above, as adopted or adapted by BSEE, would be considered BAST.

  BSEE should incorporate performance standards identified through this BAST process into its regulations, as appropriate. Priority should be given to those items identified in the initial BAST gap analysis that are not covered by regulation.

  BSEE should maintain its existing regulations through which new technologies, processes and equipment can be approved, including approval of alternate procedures and equipment (30 CFR 250.141); approval of departures from the regulations (30 CFR 250.142); and incorporation of standards by reference (30 CFR 250.198).

  BSEE maintains its authority to require or authorize technologies, equipment and/or processes through its existing rule-making process.

Safety Management Systems (Reference material found in Enclosure 3)

- ***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, USCG, Department of Transportation (DOT) and others could then request that responsible parties have a Safety Management System which is consistent with API RP 75. Each agency could then decide how it will assure the adequacy of the Safety Management Systems in so far as it pertains to the agency's individual responsibilities. Memoranda of Understanding (MOUs) between the agencies should address issues of review, inspection, and/or audit of various aspects of the Safety Management Systems.

- ***BSEE should amend the Safety and Environmental Management System (SEMS) regulations such that "major contractors", in addition to the Operator[1], 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[1] 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[1].***

  30 CFR 250.105 Definitions
  Operator[1] means the person the lessee(s) designates as having control or management of operations on the leased area or portion thereof. An operator may be a lessee, the BSEE-approved or BOEM-approved designated agent of the lessee(s), or the holder of operating rights under the BOEM-approved operating rights assignment.

- ***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 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.***

<u>Spill Containment</u> (Reference material found in Enclosures 4)

- ***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.

- ***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.***

Ocean Energy Safety Institute (Reference material found in Enclosure 5)

- ***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. The Institute would support BSEE's missions regarding offshore safety and environmental management through various means, which may include:***

  - research and development, including development and maintenance of a technology research and development (R&D) roadmap and dissemination of research results;
  - facilitating a new BAST process;
  - facilitating communication and collaboration among entities involved in offshore safety and environmental management through workshops and other methods; and
  - other topics as may be identified in the future.

  Establish a board or steering committee consisting of relevant government agencies, industry, academia, non-governmental organizations, and other centers of expertise that would help to develop the OESI's initial goals and strategies, and provide ongoing strategic and technical advice to the Institute.

  Note: The paper should be attached to any transmittal of this recommendation to provide the context for and details of the recommendation.

Arctic (Reference material found in Enclosure 6)

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

  Although some existing regulations and national Notices to Lessees are applicable and sufficient for Arctic activities, BSEE regulations as written do not specifically address all the Arctic operating conditions. In particular, to ensure full system readiness for Arctic OCS exploration and production, BSEE/DOI (in coordination with other agencies, as appropriate) should do the following;

  - ***Spill Prevention - 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.

- ***__Safety Management__ - 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.***

- ***__Spill Containment__ - 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.***

- ***__Spill Response__ – 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.***

  In particular, OSRP regulations and associated permitting regulations and approvals should address at least the following elements:

  - Seasonal drilling limitations that consider the timing and adequacy of oil spill response operations, given available technologies and type of drilling operation.
  - Prompt deployment of response equipment and adequately trained personnel.
  - Ice capable equipment appropriate for expected conditions.
  - Adequate strategies and equipment to protect important ecological and subsistence areas that could potentially be impacted by an off-shore oil spill.

- ***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.***

  The USCG classifies OSROs to better validate capabilities and suitability of companies providing response resources listed in industry response plans they regulate. BSEE conducts similar inspections to ensure an OSRO's equipment and personnel meet industry planning requirements as specified in OSRPs.

  The USCG OSRO classification program is presently not climate specific. To help ensure that equipment and personnel listed in OSRPs are sufficient for responding to spills in the Arctic OCS, BSEE should collaborate closely with the USCG, EPA and PHMSA to share information and establish common expectations, consistent requirements and coordinated inspection regimes for OSRO equipment and personnel.

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

  An OSRP must demonstrate that an operator can respond quickly and effectively whenever oil is discharged from one of their facilities. This requires that the equipment be in good condition and that crews have the skills necessary to operate this equipment safely and to its maximum potential.

  Existing regulations provide for exercises, training, and inspections to validate that spill response equipment is being maintained and can be deployed quickly when called upon.

  As the Arctic is a frontier area and response equipment listed in OSRPs may be largely new or may not have been subject to inspection by BSEE, the OESC recommends that BSEE evaluate the need to require deployment of categories of response equipment listed in an OSRP that have not yet been successfully deployed, in advance of the initiation of drilling operations where such equipment might be used.

- ***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.***

  The SCP describes the strategy for a coordinated federal, state and local response to a discharge or substantial threat of a discharge of oil or other hazardous substance from a vessel, offshore or onshore facility or vehicle operating within the boundaries of the North Slope Subarea. For the Arctic OCS, OSRPs must be consistent with the SCP.

  DOI should work with other agencies and stakeholders to increase their involvement in updating the SCP and to support the public engagement process, especially in reaching out to local communities. Ongoing consultation with tribes and local communities could provide important information to planners with regard to environmental sensitivities and raise preparedness awareness.

  DOI should ensure that all of its Bureaus with expertise and/or responsibilities in the Arctic contribute to the SCP process through the DOI representative on the ARRT.

BSEE can work with other ARRT members to ensure that the SCP has scenarios that are updated or developed that are applicable to existing and proposed offshore exploration and production activities.

- ***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.***

  Although OSRPs must be approved by BSEE's Oil Spill Response Division, BSEE may provide these plans for review by other federal agencies. In locations where the State of Alaska has jurisdiction, it may conduct its own review.

  For recent operations in the Beaufort and Chukchi Seas, a process was initiated to provide for additional reviews of OSRPs by the USCG, EPA, NOAA and other federal agencies with expertise in preparedness and oil spill response in the offshore environment. This interagency review process should be continued.

  The OESC supports recent BSEE actions to make redacted versions of approved Arctic OSRPs freely available to the public. This will ensure public and stakeholder awareness of the level of containment and response preparedness in the Arctic OCS and how elements of the SCP are being implemented in Arctic OSRPs.

- ***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.***

  With Arctic OCS oil and gas development likely in the years to come, DOI/BSEE will encounter new scientific, engineering and regulatory issues related to the Arctic's challenging operating environment.

  One way for BSEE to obtain early and ongoing multi-stakeholder input would be through continuation of Arctic Subcommittee of OESC.

  The intent of this continued Subcommittee would be to address technical and regulatory issues needed to improve safety in offshore and related operations and protect marine ecosystems and nearby coastal areas.

Beyond the recommendations above, I would like to highlight some supporting information about the recommendation regarding a workshop on underground blowouts and sea-floor broaches from the Committee's efforts on containment. This recommendation was similarly provided in earlier letters, but I feel that its intent and importance was not conveyed by my earlier letters. This recommendation is supported by an explanatory document **(Enclosure 4)** which should be taken into consideration along with the recommendation. Our recent discussions also revealed that this workshop could be sponsored by BSEE perhaps in conjunction with the Society of Petroleum Engineers and conducted under the auspices of the OESI, which is the subject of a separate recommendation by the OESC. Two leading professors in reservoir geomechanics have already been contacted and expressed an interest in co-leading such a workshop. Industry co-leaders would be identified once the workshop is approved, perhaps through the Center for Offshore Safety or the OESI. This workshop is viewed as adding a critical dimension to the oversight and regulation associated with any containment of future events.

We look forward to your response on these formal recommendations and any other input you may have for the Committee at your earliest convenience.

Sincerely,

Thomas O. Hunter

Thomas O. Hunter
Chairman
Ocean Energy Safety Advisory Committee

Final - 12/19/2012 -

Enclosure 1

Vector 2: Recommendations on development and implementation of data analysis, alarm, and automated control systems to help prevent loss of primary well control

Background

Drilling continues to grow in complexity, including not only the wells themselves but also drilling rigs and the types and volumes of data available from drilling operations. Thus the work and tools of the rig staff must also change to better inform and support decision making and provide improved well control and enhanced spill risk mitigation. This must be achieved thru a priority based road-map that follows a step-wise approach to developing and implementing automation technology. This approach must consider the key human factors for choosing the right level of automation and ensure that automation technologies and learnings from other industries are fully evaluated and transferred.

The safe and effective control of an offshore well requires dealing with many complex and highly varied activities. During drilling it is critical to detect and control influxes from the formation as early as possible, thus minimizing the total mass and volumetric size of formation hydrocarbons that are allowed to flow into the well (known as a “kick” or well control incident). Well control must also be maintained during other types of rig operations. Much of the time on a rig does not involve drilling of the well itself and is often called “flat time” (i.e., tripping pipe, running casing, circulating & conditioning, cementing, changing out mud systems, testing, etc.) Well control events can also occur during these flat time activities when the alignment of the fluid circulation system may be different and the instrumentation and data that are part of normal well control monitoring may not be available. For example, there are times when well fluids are not circulated and therefore no delta flow rate data are collected. Thus, consideration of improved monitoring and well control during flat times must be addressed in automated well safety systems.

Historically, there are many factors that prevented the application and use of automated control systems on drilling rigs. Among these are mistrust of the system based on perceived unreliability and concern regarding false alarms. In particular, there has been resistance to using an automated system that could result in activation of the shear rams and release of the drilling riser at the lower marine riser package (LMRP) without rig crew awareness or control. If this occurred as a result of a false alarm, it could result in additional risks to the rig crew and recovery of the well would be difficult and costly. If it happens during an actual well control event, it would eliminate many well control options that could be more effective, including the option of full well recovery. Lastly, an unplanned shut-in by the shear rams may result in high pressure build-up below the BOPs that could result in subsequent failures of the well system in even more uncontrollable ways, such as through an underground blowout and seafloor broach (discussed by the Containment Subcommittee). This high pressure build-up is avoided by normal well control responses that do not involve the shear rams. Thus, it is important to fully assess the most effective level of the automation to be used and implement control actions in a step-wise approach, with opportunities for human intervention at key decision points.

Findings

Robust instrumentation, data stream analysis, alarms and automatic control systems are critical components of an automated well safety system and should be incorporated into all rig operations where there is a risk of loss of well control. This automated well safety system should:

- identify abnormal well situations
- provide adequate, rapid, clear, and easily understandable information to the driller to remedy a well control situation
- take over well control and 'make the well safe' if the driller does not take appropriate action in a specified time frame

When an automated well safety system takes control it would shut down the drilling process (pumps, rotary drive, etc.), hoist the drill-bit off bottom and close the BOPs on the pipe – but without shearing the pipe.

In the past couple of decades automation of safety critical functions has gained prominence as a means to avoid catastrophic accidents due to human error. The Federal Aviation Administration (FAA) and the Nuclear Regulatory Commission (NRC) have both adapted 'automation' of safety critical systems, but levels of automation (LOA) are vastly different. LOAs vary between Fully Manual to Fully Automated. A simple 5-level system often used in these other industries is as follows:

Level of Automation	Functional Description
Fully Manual	Human decides and acts with no assistance from the computer in the decision making. Human may rely on computer monitoring of sensors and displays.
Decision Support	Human decides and acts but with suggestions from the computer systems. This is generally important for complex systems where dynamics of the system is not completely understood.
Consensual Control	Computer system decides and acts with concurrence of the operator. Human-machine-interface is vital in this case to facilitate effective operation and provide common situational awareness (SA) of the system.
Monitored Control	Computer system decides and acts unless vetoed by the operator. Operator complacency and skill degradation is a major issue
Fully Automated	Computer system decides and acts with no intervention from the operator. Operator may be a part of the recovery if safety critical functions were not executed properly.

Further refinement of LOA can be achieved by explicitly defining who or what (human or computer or both) is responsible for what tasks. Tasks in process control can be broadly divided into four categories: Detect and Alert, Contextualize (i.e., interpret what is happening based upon data received), Select (i.e., decide on actions), and Act.

Safety systems in a nuclear power plant are autonomous, and require no human interaction, thus they are “fully automated”. While some non-safety systems in a nuclear power plant are “fully manual,” most systems fall somewhere in between “fully automated’ and “fully manual.”

For an automated well safety system, the suggested LOA is “decision support.” At this level both humans and the computer are detecting and contextualizing, whereas humans are selecting and taking action based on this contextualizing. In addition, for an automated well safety system, the computer should take action if the human fails to do so within a specified time frame. The “decision support” LOA for offshore drilling safety met the general criteria for selecting LOA’s in complex systems design: human performance, automation reliability, and cost associated with outcomes. Specifically, this LOA provides the following attributes:

1- It does not eliminate human responsibility for action which minimizes potential for operator complacency, vigilance decrements, and skill decay over time;
2- It moves the well to a “safe” state without going to an unrecoverable state of pipe shearing. This provides time for further analysis, intervention, and recovery; and
3- It allows human-only selection and action when moving to the unrecoverable state of pipe shearing.

As experience is gained with “decision support” automation and as technology changes, moving to higher levels of automation should be considered while taking into consideration human factors analyses for automation of safety critical systems.

To allow a move to a “decision support” LOA, the automated well safety system should include the following components and features:

Alarms - Current drilling rigs have too few alarms on critical data streams, and those that do exist are often poorly integrated. This situation requires too much reliance on humans for pattern recognition and the analysis of problems from the data presented. All data streams important for well control – including the determination of well influx or lost circulation - should be alarmed to alert the driller and other rig staff. These alarms must be tied to reliable sensors (as discussed under Vector 1), as trusting the alarm is a key to successful response on the rig. New alarming technologies need to be developed and added to rigs that take advantage of improved behavioral response and avoid “alarm fatigue” and complacency. Any new data streams should be alarmed if they are critical to well control awareness and recognition.

Computer-Based Displays & Data Stream Analysis - A modern rig floor already has multiple data displays of varying complexity, supporting simultaneous operations and both automated and remotely operated machinery. Humans are required to monitor, analyze, and take action on this vast array of data. To enhance awareness and decision-making by drillers and other rig staff, rig alarms and data streams must be interfaced with a computer system that performs effective pre-processing, analysis, and prioritization. Such a system could identify critical issues and support the decision-making process, perhaps including recommended actions. However, system-generated recommended actions could possibly lead to a practice of “blind acceptance” over time, which may lead to different operational problems and/or unintended outcomes. Development of improved methodologies for data stream analyses and presentation in offshore drilling should take advantage of recent human/machine interface R&D from other industries, such as aviation.

Well Flow Detection Algorithms - Well control has historically been based on the fundamentals:

1. flow into the well should equal flow out of the well; and
2. the total pressure at the formation face imposed by drilling fluid density plus flow induced pressure exceeds the formation pressure.

However, with modern deep and complex wells – and especially deepwater wells where there is a small margin of difference between the formation fracture pressure and pore pressure – well inflow behavior can be quite complex and sometimes difficult to recognize. This recognition is made even more difficult by high density and/or synthetic mud systems, which can take considerable volumes of formation gas into solution and cause any free gas to be volumetrically small when deep in the well. Additionally, there is the effect of well “ballooning” or breathing, wherein a well can lose drilling fluid and then gain drilling fluid back without actual formation hydrocarbon influx or actual drilling mud loses. Although good models for many of these processes already exist, more work is needed to ensure that these models are effectively and correctly built into future automated rig safety systems. When combined with the enhanced kick detection sensors and technologies (both surface and downhole) described in Vector 1, improved well flow detection algorithms would provide a much more rapid and accurate well control system than presently available. Furthermore, these various models and algorithms must be adequately covered in well-control training and staff capability assessment exercises to ensure competency in understanding all types of well flow. Finally, new models need to be developed for how wells flow and how this flow can determined during cementing, testing and similar non-drilling operations where mud is not being circulated.

Automated Control Systems – Current drilling rigs have few automatic systems for well control. If judiciously applied, automated control systems could reduce well control hazards resulting from human-based pattern recognition and manual response times that can be too slow. As discussed above, there are various levels of automation that can be implemented to take control of an operation when human operators fail to do so. However, design of such automated control systems is complex and requires careful analysis of which tasks should be assigned to the automation and which to the humans. Many human factors must be considered in the determination of the appropriate LOA, such as the need to maintain skills and confidence in the staff. Automated control systems can potentially create new hazards by incorrectly responding to or overcompensating for a rapidly evolving situation, especially with multiple and/or contradictory data inputs. Thus, comprehensive hazard analyses and failsafe design techniques must be applied to any added automated control process. However, a minimum industry goal should be an automated well safety system that moves the well to a safe condition if the rig crew does not respond within a given time frame.

Summary - An automated well safety system should:

- Be reliable
- Provide automated alerts and recommended actions
- Initiate/support an Automated Well Control Response

- Be implementable by the rig contractor

Improvements are needed and should be applied in the areas of:

- Alarms
- Computer-based displays & data stream analysis
- Well flow detection algorithms
- Appropriate application of automated control systems

The system should advise the driller and other rig staff on well control using surface measurements, numerical flow models and control theory. The system should also support automatic well shut-in if the well control situation sufficiently escalates without other well control action.

A well safety automation system can be realized through a combination of R&D and technology development in the defined improvement areas and the application of existing technology from other industries. These improvements, when combined with the Vector 1 improvements in instrumentation and downhole detection, would result in a well safety automation system that focuses on delivering automation related to the initial well shut-in associated with well control events, i.e. shut-in on the annulars and pipe-rams. This well safety automation must be independent of the drilling operations control systems (control of normal rig equipment) and of the drilling optimization systems (control of the drilling process to reduce drilling times and protect the drill string). The automated well safety system should be owned and operated by the drilling contractor and be part of the drilling rig equipment. This should not change the responsibilities of the lease-holder/operator, or the responsibilities of any regulatory defined “person in charge”. Ownership of the automated well safety system by the rig contractor is intended to promote active and continuous training and competency of the contractor and their rig staff in the use, maintenance, and monitoring of the system. This is no different than the evolution of other rig equipment that has become more automatic with fewer human interactions. Lease-holder/operator staff should also be trained and competent regarding such systems via their well control training.

Recommendation

The OESC recommends that a BSEE facilitated JIP be formed to address the improvements needed in automated well safety systems. The JIP would:

- Establish the ultimate goal of automated well safety systems
- Establish a technology roadmap with a step-wise approach to the goal
- Determine the gaps between existing projects and the need for additional work
- Determine technology that should be adopted from other industries
- Recommend appropriate parties for newly identified projects
- Recommend an oversight and alignment mechanism to monitor and assure progress

Participants in the JIP should include expertise from the following organizations:

- Government agencies such as BSEE, USCG, USGS, DOE, and NOAA
- Industry companies from operators, equipment manufacturers, service companies and drilling contractors

- Academia
- National laboratories

Funding for the JIP would be derived from either Federal appropriations or revenue from Federal royalties, rents, and bonuses on Federal offshore oil and gas leases issued under the Outer Continental Shelf Lands Act. In addition industry would provide “in-kind” and monetary contributions. Monitoring/oversight of the JIP could be performed by the Offshore Energy Safety Institute (OESI) as recommended by the OESC.

Both the R&D and the implementation of new and existing technology on drilling rigs should follow a step-wise approach, prioritized on the basis of benefit and practicality and using the results from past and ongoing studies being conducted in these areas. Because of the large number of existing projects and the need for new projects, a single BSEE facilitated JIP should be formed to recommend what new projects are needed to close gaps. These gaps will be determined from the JIP compilation study of current projects in the industry and existing technologies from other industries. The single, unified report from this JIP will establish overall priorities and a road-map for the step-wise approach going forward. Additionally, BSEE should be a funding partner in the JIP.

The single JIP should combine industry, academia, and government labs. The resulting road-map should not only recommend new projects to fill gaps but also recommend the most appropriate parties to execute those projects. The OESI, or similar organization that the OESC recommends, should monitor progress of the established new projects and existing projects.

Enclosure 2

Vector 3: Recommendations on Implementing a Process for Best Available and Safest Technology

Background

The OCS Lands Act requires the use of Best Available and Safest Technology:

> …the Secretary … shall require, on all new 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. 43 USC 1347(b)

Current BSEE regulations (30 CFR 250.105) repeat this requirement. Subsequent sections of the regulations add:

> 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. 30 CFR 250.107(c)
>
> The Director may require additional measures to ensure the use of BAST:
> (1) To avoid the failure of equipment that would have a significant effect on safety, health, or the environment;
> (2) If it is economically feasible; and
> (3) If the benefits outweigh the costs. 30 CFR 250.107(d)

These are the only provisions of BSEE's regulations that specifically address BAST, but they are not the only means by which new technologies, processes and equipment can be approved. Existing regulatory processes include approval of alternate procedures and equipment (30 CFR 250.141); approval of departures from the regulations (30 CFR 250.142); and incorporation of standards by reference (30 CFR 250.198), all of which serve an important role.

In his letter of August 10, 2012, BSEE Director James Watson asked the OESC to address BAST:

> In particular, we would appreciate your input on the following:
>
> ***
>
> - In an effort to foster greater innovation for safety and oil spill prevention/response research and development both at BSEE and with

> industry stakeholders, we seek further guidance in how to best stimulate private sector interest and investment into BAST, as well as a procedure to determine BAST on rolling, real-time basis….

Findings

The current regulatory approach to BAST states, in general, that compliance with BSEE's regulations is sufficient to meet the BAST requirement. This raises certain issues:

- The current language can promote a compliance mentality in parts of the regulated community. Better and safer technologies than required in the regulations for safety critical operations may not be used by all operators even if they are available and are economically feasible.

- If better and safer technology becomes available, the regulations may not change quickly enough to incorporate them (see *Report to the President, National Commission on BP Deepwater Horizon Oil Spill and Offshore Drilling*, January 2011, p. 73).

- The onus is on BSEE to proactively identify BAST technologies for incorporation into the regulations.

While BSEE's regulations do not facilitate BAST, neither do they hinder the development of new technologies. Industry has been responsible for innovation and continuous technological improvement, as evidenced by the expanded frontiers in ultra-deep drilling and drilling in deep water. These advances, often at a rapid pace, underscore the need for an effective process that allows the regulator to keep pace with technology innovation while providing regulatory certainty for those proposing new technologies, equipment or processes.

By definition, BAST refers to available technology. However, there is also a need for a process by which new technology, processes and/or equipment can be efficiently evaluated by BSEE. In 2002, BSEE's predecessor bureau conducted a workshop with the Offshore Technology Center of Texas A&M University to address the issue of new technology. The conclusion of that workshop was that a process, and potentially a "standard," could be developed by industry and the regulatory agency to enhance and improve the assessment of technology. The output of this workshop was not a draft standard that determined or defined BAST, but one that assured the design, specifications and manufacturing of new technology would deliver a safe product.

The subcommittee reviewed approaches taken by other government agencies that have "best available technology" requirements, and identified three general approaches to identifying BAST: (1) the regulator identifies BAST; (2) a competent third party does so; or (3) a hybrid approach in which a competent third party provides information and advice to support decisions by the regulator.

In the first approach, the regulator sets objective, quantifiable performance standards and then allows any technology that meets or achieves those standards. The regulator also could identify acceptable BAST technologies and the performance levels of those technologies, and allow any other technology that performs at least as well. This approach works best when there is a technology or an objective performance standard that captures the goal of the regulating agency, such as an emissions or effluent standard that is easily measureable. Where this approach is suited it should be used, but the subcommittee believes that this approach may not be well suited to many facets of offshore oil and gas exploration and development. While identifying technologies or setting performance criteria may be possible for some components of OCS facilities, there are too many components in an offshore operation to set such standards[1] for all of them. In addition, the value of such performance standards for key pieces of equipment may be difficult to ascertain when the events that define failure are rare.

The other two approaches are similar in concept, with the primary difference being who is responsible for identifying BAST – the regulator or the competent third party. Because BSEE is charged, by statute, with ensuring safety and environmental protection, the subcommittee believes that BSEE must be free to make final decisions within its areas of jurisdiction. However, the expertise that others can provide is essential to a robust BAST process. Therefore, the subcommittee believes that the best approach is one that abides by the following principles:

- The ultimate decision as to whether to accept an item as BAST rests with BSEE.

- The primary responsibility for qualification and development of technology processes and equipment lies with industry.

- A BAST process must include expertise from all sectors. As the source of technological innovation, industry must be included. But there is also considerable expertise among regulators, other government agencies, manufacturers, classification societies, testing laboratories, and academia that should be included.

- The process should not endorse discrete solutions or specific products, but provide a basis for establishing appropriate performance standards.

- BAST should focus on technologies, equipment and/or processes that are the most critical for safe operations.

- The BAST process must recognize the statutory language concerning the economic feasibility of BAST. A BAST process must consider:

[1] For this paper, the term "standard" is intended as a generic term to indicate a requirement imposed by the regulatory authority. A "standard" could take a variety of forms, such as specific performance criteria or a required practice. The type of requirement put in place will vary based on the specific circumstances of the technology, equipment or process being assessed. The decision on the type of standard to use for each circumstance is best determined by BSEE and is not further addressed in this paper.

  - The context of the operating environment, e.g., BAST for deepwater Gulf of Mexico might be unnecessary for shallow water, shallow depth operations or inappropriate for the Arctic OCS environment.
  - The practicality of retrofitting existing facilities.

- A BAST process must be evergreen – it will need to evolve as additional technologies are evaluated; as evolution in a given technology necessitates reconsideration of past evaluations; and as new technologies are developed in response to new challenges.

The competent third party partner for BSEE should be the Ocean Energy Safety Institute (OESI), which is the subject of a separate recommendation of the OESC. Such a function for the OESI would be symbiotic with other functions being considered for this Institute, such as developing a roadmap for research and fostering government/industry/academic collaboration to develop improved technologies and safety practices for the offshore energy industry. However, if an OESI is not established, BSEE should develop other options for obtaining third party expertise (for example, BSEE could contract with a National Lab or university to manage the BAST process).

Recommendation

The OESC Spill Prevention Subcommittee recommends:

1. <u>BAST Process:</u>

   BSEE should establish a process for implementing the BAST provisions of the OCS Lands Act, through a partnership with the proposed Ocean Energy Safety Institute. Specifically:

   a. BSEE, with input from OESI, would identify and prioritize the technologies, equipment and/or processes to consider based on OESI's work to identify safety-critical technology and regulatory gaps, and the results of investigations into offshore incidents.

   b. For the chosen technologies equipment and processes, industry standards organizations would develop testing protocols for establishing performance levels, failure points, and reliability. The criteria should be based on the operating environment in which the technology would be used.

   c. OESI would facilitate forums that convene the relevant expertise to provide input to BSEE on BAST-related topics, including the suitability of test protocols, establishing performance standards based on test results, and analyses of the costs and benefits of applying relevant standards across the OCS. These forums would recur on a regular basis to support the goal of an evergreen process. These forums could also be used to provide peer review to technology projects being carried out by other entities (e.g., oil and gas companies; manufacturers; research consortia), by reviewing testing and assurance data and advising on whether the technology is ready to be tested/used on the OCS.

d. Based on input from OESI and the expert forums, BSEE would decide whether to accept the testing protocols and evaluation criteria.

e. The critical technologies and equipment would be tested using BSEE-accepted protocols. Based on these tests, analyses of economic feasibility and input from the expert forums, OESI would recommend performance standards. The OESI recommendations would also address, based on the economic feasibility analyses, whether the standard would apply prospectively only or would also apply to existing facilities. BSEE would then adopt performance standards for BAST based on its consideration of these OESI recommendations. Operators would be required to meet BSEE-adopted performance standards.

2. <u>BAST-Related</u> <u>Regulations</u>:

   a. BSEE should revise its regulations at 30 CFR 250.107(c). The revision would remove the language stating that complying with BSEE regulations constitutes compliance with the BAST requirement.

   b. The revised regulation would specify that technologies and equipment that are evaluated through the BAST process recommended above, as adopted or adapted by BSEE, would be considered BAST.

   c. BSEE should incorporate performance standards identified through this BAST process into its regulations, as appropriate. Priority should be given to those items identified in the initial BAST gap analysis that are not covered by regulation.

   d. BSEE should maintain its existing regulations through which new technologies, processes and equipment can be approved, including approval of alternate procedures and equipment (30 CFR 250.141); approval of departures from the regulations (30 CFR 250.142); and incorporation of standards by reference (30 CFR 250.198).

The new BAST process should be incorporated into BSEE's regulations. Because the BAST process would be limited in scope – initially due to limited capacity to address all candidate technologies at once, and later due to decisions on what technologies to include – BSEE needs to maintain its current regulatory framework for OCS activities. BSEE maintains its rulemaking authority and should use it as appropriate.

BSEE should incorporate specific BAST requirements into its regulations, in the same manner that it incorporates standards and recommended practices of others into its regulations today. However, during the time it takes to make such regulatory changes, and for those instances where BSEE decides a regulatory change is not warranted, the new process for identifying BAST recommended above would apply and exist in tandem with existing BSEE regulations. In such cases where the BAST recommendation creates an inconsistency with existing regulations, BSEE would need to determine, on a case-by-case basis, whether a regulatory change is needed or whether an NTL or other process can be used to resolve the issue.

Enclosure 3

Ocean Energy Safety Advisory Committee
Safety Management Subcommittee
Safety Management System Enhancement Recommendation

Introduction

At the previous OESC meeting in August 2012, the Safety Management Systems (SMS) Subcommittee submitted four recommendations to enhance the effectiveness of the current SEMS regulations. Three of the recommendations concerning submittal and approval of SEMS plans, revision of the inspection and audit process, and use of qualified, internal auditors for SEMS audits were supported by the Committee and subsequently submitted by Chairman Hunter to the Department of Interior (DOI) and the Bureau of Safety Environmental Enforcement (BSEE) in a letter dated October 15, 2012. However the fourth recommendation dealing with implementation of a dual level concept consisting of a "Management Level SMS" and a "Facility Level SMP" was challenged by some OESC members as being too confusing and/or burdensome, so the SMS Subcommittee agreed to work the concept further and resubmit the proposal.

The Subcommittee met on October 17, 2012 in Houston and agreed to revisit previous work and recommendations submitted by the Subcommittee and address the issue more holistically starting with the API standards that form the basis of the current SEMS regulations.

Optimum Safety Management System

As previously established, the SMS Subcommittee has focused on enhancing the current SEMS regulations and enforcement methods rather than suggesting that BSEE make a wholesale change to a different safety management system. The SMS Subcommittee believes that making modifications which resolve jurisdictional, applicability, implementation and enforcement issues with the SEMS regulations will fortify and strengthen the current SEMS regulation and will further support improving safety on the OCS.

The Subcommittee is making the recommendations below to ensure that SEMS (1) covers all operations and activities, (2) clearly identifies the responsible parties, (3) places more focus on process safety management, (4) makes the SEMS regulations less prescriptive, and (5) provides a method for evaluating and enforcing the SEMS regulation. These recommendations need to be taken as a whole as each reinforces the other and makes for a holistic approach to improving SEMS.

The subcommittee recommends the first step in achieving these goals is for BSEE, USCG, API, and the industry to participate in an up-date of API RP 75. In the interim, BSEE should continue to utilize the current American Petroleum Institute Recommended Practice 75 (API RP 75), incorporated by reference in the SEMS regulations, as the basis for SEMS. API RP 75 is robust and if modified properly it can be even more effectively used as the baseline document to support and develop optimum safety management systems for the U.S. OCS.

1) Covering All Operations and Activities: An ideal safety management system for an offshore unit[1] should be a single plan that analyzes, evaluates, and describes all operations and activities, not just ones that fall under the jurisdiction of one specific regulatory agency. Numerous daily and emergency operations, activities and systems onboard offshore units have the tendency to blur jurisdictional lines. Under the current SEMS regulations only a portion of the hazards associated with these operations and activities fall specifically under BSEE jurisdiction. Other aspects where the USCG has jurisdiction onboard an offshore unit, as outlined in the USCG/MMS MOA OCS-01, are not specifically required to be in a SEMS plan. However, operators are currently building SEMS plans to cover all facets of the operations regardless of jurisdictional responsibility. This situation can be confusing and/or inefficient, could contribute to plans that do not cover the entire system, and could provide opportunity for significant variability between operators.

   Recommendation
   The Department of Interior (DOI) working with the USCG and other appropriate agencies should request and work with industry to amend the current version of API 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, USCG, Department of Transportation (DOT) and others could then request that responsible parties (to be defined below) have a Safety Management System which is consistent with API RP 75. Each agency could then decide how it will assure the adequacy of the Safety Management Systems in so far as it pertains to the agency's individual responsibilities. MOUs between the agencies should address issues of review, inspection, and/or audit of various aspects of the Safety Management Systems.

   In this manner there will be no need for the agencies to alter their jurisdictional responsibilities which can continue to be addressed via MOUs and MOAs. We will discuss below specifically how BSEE can carry out its jurisdictional responsibilities under this recommendation and also address the issues of responsible party, placing more focus on process safety, make the requirement less prescriptive and assure enforcement.

2) Responsible Party: As currently written the preamble for the SEMS regulations specifically states, "This final rule does not require that a contractor have a SEMS program." At the same time BSEE has stated its intention to hold "contractors" responsible for compliance with the operator's SEMS plan. However, SEMS requirements cover all OCS oil and gas operations under BSEE jurisdiction including drilling; production; well construction; well completion and/or servicing; and DOI pipeline activities; whether they take place on production facilities or contractor owned and operated MODUs. This is very confusing.

   Many of the activities that are supposed to be covered in a SEMS program are actually performed by contractors and not the operator. In particular, almost every MODU operating on the OCS and some floating production units are not owned by an operator, but rather owned and operated by a contractor. Under the current SEMS regulations, the operations and activities being conducted by these contractors, for example work being

[1] For the purposes of this paper, the term "offshore unit" means a vessel, installation, structure, or other apparatus engaged in OCS activities, including all fixed and floating facilities (e.g. FPSO, FPS, etc.) and mobile offshore drilling units (MODUs).

conducted on a MODU, are supposed to be addressed in an Operator's SEMS program. This implies that each Operator is responsible for addressing safe work practices, job safety analysis, mechanical integrity and training on requirements onboard contracted MODUs or production units. BSEE introduced further confusion as to who is ultimately responsible for each requirement under the current SEMS regulations by using the term "you" instead of clearly defining the responsible party in the regulations.

Currently, many operators require major contractors to have a SEMS plan along with appropriate bridging documents. This practice is effective, but not consistently applied. Further the auditing of major contractor's SEMS is not clear. The SEMS of a major contractor should be audited by the operator or via a centralized process like that provided by the Center for Offshore Safety.

The SMS Subcommittee supports the principle that the Operator is ultimately responsible for operations and activities that take place in their own leased area. However, certain "major contractors" should be responsible for developing and implementing a facility specific SEMS program since they are the ones performing the operations and activities on the OCS. For the purposes of this paper, the term "major contractor" means drilling contractors and production facility owners/operators when not considered to be the leaseholder.

Recommendation

DOI should amend the 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 and that bridging documents are required between Operators and these "major contractors" to adequately detail linkages between respective safety management systems and specific roles and responsibilities. The term "major contractor" means drilling contractors and production facility owners/operators when not considered to be the leaseholder.

In the interim, while these regulatory changes are being made, DOI should work with its regulatory partners to encourage and facilitate "major contractors" to voluntary SEMS compliance. By demonstrating compliance with SEMS, contractors can greatly enhance offshore safety and assist operators with compliance[2].

3) Reinforcing process safety focus and responsibilities: The current SEMS regulations and API RP 75 on which they are based includes the process safety controls and requirements necessary to provide major barriers to prevent catastrophic events from occurring (e.g. hazard analyses, management of change, safe work practices, etc.). However, reinforcement of process safety management is needed from both the regulators and industry to create the change in performance and effectiveness of process safety to assure the desired culture of safety. As evident in recent catastrophic events, too much attention and effort by senior management and regulators was directed toward ensuring and recognizing good occupational health and personal safety performance rather than inquiring about the

[2] Note: contractor members of the Center for Offshore Safety have agreed to have their safety management systems certified as SEMS compliant.

integrity of the risk management controls or the robustness of decision-making in the operations.

A change to this management bias towards occupational health and safety requires a fundamental shift in approach, possibly utilizing a separate safety management system focused solely on process safety management. The SMS subcommittee debated this idea vigorously, but could not agree whether different systems are essential for success. The argument for a separate process safety management system is that the processes and measurements are very different for this type of risk management. When combined with occupational safety management, it is possible that process safety does not get the required attention because occupational safety is so well defined and established, while process safety is less so. The opposing argument is that better definition of and focus on process safety in SEMS would overcome this bias.

Recommendation

Consistent with the approach to optimize SEMS rather than introduce a new safety management system, the SMS subcommittee recommends that BSEE work with industry to develop an assessment methodology and/or audit protocol along with appropriate performance measures that test the process safety focus and controls as part of a regular SEMS review. This performance assessment could be developed in conjunction with the Center for Offshore Safety and should be supported by appropriate leading indicators that should be regularly reported.

4) Making a Less Prescriptive Regulation: BSEE has claimed that the SEMS regulations are "performance-based standards similar to those used by regulators in the North Sea." The SMS subcommittee does not fully agree with this statement, but feels that the right kinds of modifications to the existing SEMS regulations could help DOI reach their goal of SEMS being a more performance-based regulation.

Practically speaking, the SEMS regulations are written in such a manner that operators are not given the freedom to develop a management system that best fits their specific operations. Unlike the performance based regulations found in Norway and in the UK, BSEE elected to prescribe specific items to be addressed, list items that need to be verified, and even specify what records to keep in the current SEMS regulations. If SEMS was truly a performance-based regulation, BSEE would not have needed to use the words "must" and "shall" throughout the regulation.

The SMS subcommittee believes that the prescriptive approach found in parts of the current SEMS regulations could promote the idea that operators only have to meet the minimal requirements in order to comply with the regulations. This is reinforced by the PINC list which focuses more on whether an operator has the correct documentation rather than the practical operation of safety measures.

Opponents of performance-based regulations claim that they rely too heavily on the use of probabilistic risk analysis, are difficult to oversee without an extensive and technically-sophisticated governmental workforce, do not adequately consider low frequency and high consequence events like the ones that led to the Deepwater Horizon incident, and inflict high costs onto small operators. On the other hand, supporters claim that performance-based regimes allow for regulatory compliance adaptability, facilitate system and technological innovation and better place safety responsibility onto those who create the risks. Said another way, prescriptive-based regulations tend to encourage a "culture of compliance" while performance-based regulations tend to encourage a "culture of safety". The 1990 Marine Board Report on "Alternatives for Inspecting Outer Continental Shelf Operations" addressed how existing enforcement mechanisms employed by the predecessor of BSEE, the Minerals Management Service, encouraged a culture of compliance.

The diversity in the size of the operating companies in the Gulf of Mexico as well as in the size and type of facilities and the associated production that flows through or is produced by each facility creates a challenge to the regulators and the operators.

Recommendation

The SMS subcommittee recommends that the safety regulations assure that SEMS can be applied in a "fit-for-purpose" way that differentiates between facilities based on criticality and consequence. SEMS should be performance based and adapted to the needs and requirements of the business and the operating systems. For example, the regulation should not impose the same prescriptive requirements on a free standing caisson with minimal production and facilities as on a platform with complex facilities, high production rates, and living quarters.

In switching to a less prescriptive based regulation, the regulatory body must first establish a suitable regulator structure, one that is sufficiently funded, well-resourced and skilled enough to handle the responsibilities that come with implementing and ensuring compliance with a performance-based regulatory regime. The SMS Subcommittee identified the following four characteristics that are vital to the successful implementation of performance-based regulatory regimes in both the UK and Norway. These same three features also make the use of performance-based regulations very difficult to implement here in the United States:

a) *Well-resourced and competent regulator***.** The UK and Norway employ a large number of highly educated personnel and technical specialists to perform audits, inspections and reviews of required documents. In Norway, the PSA has approximately 160 employees, of which, approximately 100 perform compliance and audit related tasks regulating 105 offshore units (MODUs, FPSOs, fixed faculties, etc.). Each of these 100 employees has a postgraduate (Master's Degree), or equivalent level of training, in one or more areas of expertise, including drilling, petroleum engineering, structural engineering, and reliability engineering.

b) *A single regulatory agency, responsible for offshore safety.* Following the occurrence of major accidents and the adoption of performance-based regimes, both Norway and the UK established single offshore regulatory agencies (Offshore Division of the Health and Safety Executive in the UK, and the Petroleum Safety Administration in Norway). Each of these regulatory agencies were established with jurisdiction over all operations/activities and tasked exclusively with ensuring offshore safety in the oil and gas sector.[3] Partially driven by the need to split responsibilities of revenue collection and safety regulation, both countries decided that the "single regulator" approach would reduce industry confusion, condense the number of overlapping acts and regulations and ensure a consistent compliance/enforcement techniques. In the U.S., both the BSEE and the USCG have significant authorities and jurisdictions in regulating offshore oil and gas operations and activities. In addition, there are several agencies, such as the EPA, PHMSA, BOEM that play different roles in offshore oil and gas regulation.

c) *A single, well defined, responsible party for each offshore unit.* Under the UK approach, a single "duty holder"[4] is held responsible for all operations and activities that take place onboard each offshore unit, regardless of whether or not it is contracted or owned by a leaseholder. In Norway, the "operator"[5] is responsible for ensuring safety for all operations and activities that take place within their leased area. Whether this person is called the "duty holder" or "operator", performance-based regulations in the UK and Norway operate under the concept that there should be a single responsible party in charge. For example, if "Company X" is listed as the "Operator" on the oil/gas license in Norway, then they would be the single responsible party in charge of managing the safety of all operations that take place within their leased area, including those conducted on a contracted MODU and any third parties performing work on that MODU.

In the U.S., this is not as simple or clearly defined. Not only is there confusion regarding who is actually in charge on each offshore unit[6], but there is even greater uncertainty as to who is ultimately responsible.[7] For example, a contracted MODU performing work in a leased OCS area under the direction of operator (as defined by 30 CFR 250), must comply with both USCG and BSEE regulations. The MODU owner may be considered responsible since they are regulated by the USCG and must demonstrate compliance with regulations found in 33 CFR Subpart N (140-147) and 46 CFR Subpart I-A (107-109) regulations. The Operator, who BSEE regulates, contracted the MODU and could be considered responsible since they own the lease and developed the required drilling plan that the MODU must use. In addition, there are third party contractors who perform operations and activities onboard the MODU have responsibilities to report to both the leaseholder and the drilling company and could be held accountable for violations or accidents.

[3] In the UK the HSE is responsible for all operations related to offshore safety; this does not include environmental response or environmental safety.

[4] Under the UK regulations, a "duty holder" is person, whether the owner or the operator of an installation, on whom duties are placed by the regulations in respect of installations, particularly to prepare the safety case.

[5] In Norway, the "operator" is considered the lease holder. In cases, where more than one company invests in the lease, there will be a single designated operator listed that has the overall responsibility to ensure safety.

[6] Issues with command and control onboard the DWH was one of the key findings in the USCG/BSEE Joint Investigation into the incident.

[7] Two recent rulings show how difficult it is to understand who has responsibility when it comes to the offshore oil/gas industry. A federal judge ruled that BP must indemnify Halliburton for damage claims under its drilling contract and another federal judge ruled that Transocean will not have to pay many of the pollution claims because it was shielded in a contract with well-owner BP.

d) *Extensive workforce involvement into safety oversight*
In the both the UK and Norway, the offshore workforce is actively involved in creating the safety case for a particular vessel or facility and has a continuing responsibility to ensure that the safety management system is robust and "owned" by everyone on that facility. During ongoing operations, members of the offshore workforce get elected to fill recognized positions as safety representatives (UK) and safety delegates (Norway) with defined roles and responsibilities such as participation in accident investigations. In the U.S., while some operators have voluntarily created similar opportunities for workforce involvement, there are no regulatory requirements to do so.

While these characteristics make it hard to fully implement a performance-based regulatory approach in the U.S., the SMS subcommittee believes that the recommendations discussed in the previous sections will enable these barriers to be overcome.

5) Evaluating the Effectiveness of a Less Prescriptive-based Approach: The 2012 Transportation Research Board special report, "Evaluating the Effectiveness of Offshore Safety and Environmental Management Systems" describes a holistic approach to evaluating a SEMS program which enables the less prescriptive approach described above to be implemented in the US regulatory environment. The SMS Subcommittee strongly supports the recommendations made in this report which agree closely with previous formal recommendations made by this subcommittee which were subsequently submitted to DOI. For completeness these are repeated below.

Previous Recommendations
Finally, the SMS subcommittee feels it's important to restate the following recommendations that were submitted by the OESC to DOI/BSEE on 15 October 2012 as being aligned and fully complementary to the recommendations listed above. Detailed write-ups on these recommendations can be found in the enclosures of that letter.

- *BSEE should develop and implement a submittal and approval process for leaseholder Safety and Environmental Management Systems (SEMS) programs. In addressing this recommendation BSEE should (a) implement this requirement over a period of time to obtain the necessary resources, and (b) consider the dynamic nature of a leaseholder SEMS program, and recognizing that this program changes, develop an adequate approval process for program amendments.*

- *BSEE should review inspection/audit practices carried out by other countries and other industries, as well as the team based approach in BSEE's Focus Facility Reviews and the California State Lands Commission facility evaluations and revise their approach to audit and inspection. In developing this revised approach, BSEE should consider the recommendations of the National Research Council report "Evaluating the Effectiveness of Offshore Safety and Environmental Management Systems."*

- *The proposed SEMS II rule requires the use of independent third party SEMS auditors. BSEE should revise this requirement and allow leaseholders to (a) perform qualified, independent internal auditing and/or (b) use a third party auditor.*

Enclosure 4

Assessing and Mitigating Risks Posed by Underground Blowouts and Seafloor Broaches

Background

Underground blowouts occur when oil or gas from a reservoir comes into contact with shallower geologic formations at pressures in excess of that formation's fracture pressure (see 1, 2, 3). Such a situation can result from poor well design, shut in of the well that exposes shallow formations to high pressure (e.g., before the well is fully cased and cemented), or mechanical damage to the casing or liner string, cement, or other engineered barriers. When the mechanical or geomechanical integrity of a well has been compromised, shutting in or capping the well can lead to an underground blowout as fluids escape into surrounding geologic formations, creating upward- and outward-propagating hydraulic fractures. Lithologic contrasts can inhibit or arrest vertical hydraulic fracture growth through associated stress contrasts, low-strength interfaces, or fluid leak-off (4-7). In an offshore setting, an underground blowout can also induce cross-flow between a high-pressure reservoir and lower-pressure, shallower sands. If these permeable sands are limited in storage capacity and vertical fracture growth is otherwise unimpeded, an underground blowout may result in uncontrolled hydrofraccing of hydrocarbons through overlying geologic formations and into the marine environment, creating a seafloor broach. Underground blowouts and broaches can also occur due to the upward migration of oil and gas along pre-existing faults or other geologic structures rather than along newly created hydraulic fractures (8, 9).

An underground blowout that broaches the sea floor can lead to large releases of hydrocarbons or other fluids into the ocean that are difficult to contain and can occur at some distance from the well head, such as during the 1969 Santa Barbara blowout (10), the 2008 Tordis, North Sea incident (11), and the 1974 and 1979 Champion Field, Brunei blowouts (12). Underground blowouts leading to surface broaches and extensive cratering have also been reported in association with drilling of geothermal energy wells (13) and steam flood operations in oil sands (14) and have been implicated in formation of the Lusi mud eruption in East Java (refs. 15 and 16 and references therein). If a seafloor broach does occur, flow to the ocean can occur over a broad region, impacting sea-surface and sea-floor operating conditions and impeding oil containment, well-kill and cementing operations.

Underground blowouts represent a significant fraction of oil and gas well blowouts reported worldwide (1, 17). During normal drilling operations their occurrence can be detected by monitoring fluid circulation volumes and pressures, although it can be difficult to detect the full extent of an underground blowout until well control becomes difficult or a broach has occurred. This uncertainty can be exacerbated in a damaged well if downhole measurements typically used to diagnose underground blowouts (i.e., temperature, acoustic, radioactive tracer or flow logging, see 18) cannot be employed due to internal blockage of the wellbore. In a well that has been shut in under high pressure (relative to the fracture pressure at a potential leakage point) and whose mechanical or geomechanical integrity is poor or unknown, it can be difficult even to detect the occurrence of an underground blowout. In this case remote geophysical imaging must be used to detect and determine the extent of an underground blowout. In particular, time-lapse (4-D) seismic profiling techniques can be employed to look for increased seismic amplitudes associated with reversed-polarity reflections from an oil or gas charge zone, development of diffraction patterns (seismic chimneys) from a rising column of hydrocarbons, or an increase in two-way travel time to a particular reflector (seismic pull down) resulting from sediment disruption and charging (7, 19–22). Water column sonar can also be used to detect early signs of oil and/or gas emanation from the sea floor. These types of time-lapse geophysical imaging techniques in conjunction with well-head pressure recording and reservoir modeling were used in diagnosing geologic integrity during shut-in of the blown-out Macondo well (23).

Two factors can exacerbate the risks posed by underground blowouts. First, a growing fracture can progress upward along the wellbore annulus, or intersect the well at a shallower depth, leading to hydrocarbon flow and soft-sediment erosion (and possible sea-floor cratering) alongside the cemented liner string. This could reduce the time required for a broach to occur and also result in a loss of mechanical support for the wellhead. Second, an underground blowout – either as a fracture to the sea floor or as a washout around casing – might be particularly problematic if these vents were allowed to continue unabated for a long enough period of time that they would not heal (i.e., close up), even if a capping stack on the well was reopened to the ocean to relieve borehole pressure.

Most underground blowouts do not develop into a seafloor broach, as the subsurface flow is fully accommodated with cross-flow into lower pressure formations. In these cases there is no surface or seabed manifestation or risk to the environment. To better understand the nature of underground blowouts, and to assess and mitigate the hazards posed by underground blowouts and sea-floor broaches during offshore oil and gas drilling, new research should be carried out to address several key scientific goals, including:

1) Better understanding the physical processes controlling upward propagation and arrest of two-phase (oil/gas) hydraulic fractures in poorly consolidated marine sediments, leading to improved numerical models for leakage volumes required for a sea-floor broach under different geological settings, geomechanical conditions, and fluid properties.

2) Improving geophysical imaging techniques (e.g., seismic reflection surveys, and possibly passive microseismic monitoring) for remotely monitoring oil and gas leakage rates and upward migration below the sea floor and external to the wellbore. (Diagnosing well

integrity below the sea floor would also be facilitated by improved wellbore instrumentation for monitoring annular pressure, temperature and other parameters, which is the subject of a separate recommendation by the Prevention Subcommittee).

3) Determining under what conditions (e.g., in-situ stress, sediment rheology, fluid pressure, flow rate and blowout duration) hydrocarbon pathways to the sea floor established through hydraulic fractures and reactivated natural faults can heal and after how much hydrocarbon release.

4) Developing improved quantitative models for reservoir response and cross-flow during blowouts to better understand subsurface behavior in a cross-flow situation. Conventional reservoir simulators are not designed to model cross flow, although there may be some experience with models for industry water-flood operations.

These research priorities are intended to better assess the overall risks posed by underground blowouts (including total release) and to help design and implement well kill and cementing operations. These long-term scientific issues would be addressed most effectively through a collaborative research partnership involving academia, industry and government research labs, beginning with a focused thematic workshop (discussed below).

Implications for Well Containment and Regulation

Better scientific understanding and modeling of underground blowouts and seafloor broaches are needed to improve well design to prevent a seafloor broach from occurring, and if it does occur, devise more effective containment strategies. There are several aspects of the well-design and regulatory process for offshore oil and gas drilling that would benefit from this type of additional research, as follows.

BSEE regulations at 30 CFR 254, as supplemented by NTL 2010-N10 for instances of subsurface blowout preventers (BOPs) or surface BOPs on floating facilities, require each operator to submit information demonstrating that it has access to and can deploy resources adequate to fully contain the flow from an offshore blowout. These containment strategies have been based on use of a capping stack or secondary BOP either to allow collection of hydrocarbons to a surface vessel ("cap and flow") or to completely shut in a well ("cap and shut in"). The industry is primarily focusing on cap and shut in because it is the most rapid and straight-forward containment method for a blowout. In this case, the well must be either designed to withstand the full shut-in pressure of the reservoirs penetrated by the wellbore without loss of mechanical or geomechanical integrity, or a case must be made that an underground blowout would be fully contained (e.g., through cross-flow into shallower permeable units) long enough for a relief well to be completed before a sea-floor broach occurs. Toward this end, some operators are researching the adaptation and use of traditional hydraulic fracturing propagation models to simulate oil and gas migration to the sea floor through hydraulic fracturing, including the effects of soft-sediment deformation and charging of shallow sands, but validating this work is difficult given the current state of knowledge. Integrated case studies of oil-well broaches and natural seeps, laboratory and borehole geomechanical studies, and modeling should be done to assure that models, within the limits of current science, most accurately predict the migration pathways, likelihood and timing for hydrocarbons to reach the sea floor following an underground blowout.

Worst-case discharge (WCD) analyses are required by BOEM's and BSEE's regulations. Both exploration plans (30 CFR 550.219) and development plans (30 CFR 550.250) need to include calculation of a WCD total volume, and these volumes must be compared to the WCD scenarios included in an operator's Oil Spill Response Plan (30 CFR 254). A better understanding of the geologic and geomechanical processes controlling the ascent and discharge rate of hydrocarbons to the sea floor following an underground blowout and broach and the coupled reservoir and wellbore response to this discharge is needed to encompass all WCD scenarios.

Although numerous cases of sea-floor broaches have been reported in the literature (discussed above), they differ greatly in severity, areal extent, geologic setting and water depth and robust containment scenarios have not been adequately developed to cover this eventuality. As more is learned about the pathways and rates for possible migration of oil to the ocean following an underground blowout, containment strategies will need to be developed and modified to address a variety of broaching scenarios. This will be particularly challenging for losses of well control in deep water, as the response to the Macondo blowout showed that traditional means for capturing oil emanating a blown-out well in shallow water – such as tents or domes – may not be effective at greater water depths due to a variety of effects. These effects include hydrate formation, differential pressure effects on large surface areas, lack of capability to separate hydrocarbons from seawater, and inability to move hydrocarbons to the surface from capture systems without pumping.

Recommendation

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.

The goals of this workshop would be to: 1) identify gaps in understanding of underground blowouts and sea-floor broaches, 2) use this gap analysis to guide future funding and research efforts within academia, private industry, BSEE and other Federal agencies, and 3) to inform future regulations by BSEE that will be guided by new scientific work and technology. This workshop would cover a wide array of topics, including hydraulic fracture propagation under single- and two-phase conditions, geologic constraints on fracture height growth and containment (e.g., due to cross-flow into shallower sands), the geomechanics of soft sediment deformation, worst-case discharge calculations under a broaching scenario, and well-bore completions to minimize risks of underground blowouts and seafloor broaches in the offshore environment.

This workshop could be sponsored by BSEE perhaps in conjunction with the Society of Petroleum Engineers and conducted under the auspices of the Ocean Energy Safety Institute (OESI, which is the subject of a separate recommendation by the OESC). Two leading professors in reservoir geomechanics – Peter Flemings, Univ. Texas Austin, and Mark Zoback, Stanford Univ. – have already been contacted and expressed an interest in co-leading such a workshop. Industry co-leaders would be identified once the workshop is approved, perhaps through the Center for Offshore Safety or the OESI.

In preparation for this workshop, we envision that participants would conduct an extensive literature search; carry out interviews with experts in industry, academia and government; and examine data and analyses from past underground blowouts in relation to geologic environment, well design, and whether or not (and under what conditions) those blowouts led to a sea-floor broach. Most of this effort would focus on offshore operations, but data and analyses from onshore underground blowouts and surface broaches could be considered as appropriate. Also, this effort should be carried out in concert with recommendations made by the Prevention Subcommittee to ensure that wellbore instrumentation needs most relevant to detection and analysis of underground blowouts are adequately addressed.

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Enclosure 5

Ocean Energy Safety Institute

Subcommittee Recommendation

January 10, 2013

Introduction

When Secretary of the Interior Ken Salazar established the Ocean Energy Safety Advisory Committee (OESC), he tasked it with developing recommendations to aid in the creation of an Ocean Energy Safety Institute (OESI or Institute). The Secretary envisioned an independent institute that would facilitate research and development, training, and implementation of operational improvements in the areas of offshore drilling safety and environmental protection, blowout containment and oil spill response. The Institute would be a collaborative initiative involving government, industry, academia and scientific experts.

In announcing the Ocean Energy Safety Institute, the Secretary identified the following specific objectives (DOI press release, Nov. 2, 2010):

- Advancing safe and environmentally responsible offshore drilling through collaborative research and development in the areas of drilling safety, containment and spill response;
- Developing advanced drilling technology testing and implementation protocols;
- Understanding full-system risk and reliability for the offshore environment;
- Developing an enduring R&D capability and an expertise base useful both for preventing and responding to accidents;
- Developing training and emergency response exercises;
- Increasing opportunities for communication and coordination among industry, government, academia and the scientific community;
- Developing a larger cadre of technical experts who can oversee or otherwise participate in deepwater drilling-related activities;
- Establishing cost-effective advances in technology for industry; and
- Creating a framework for regulatory predictability in a global market.

In developing its recommendation for an Institute, the Committee recognized that some of these objectives are being addressed by other parties, including the Interagency Coordinating Committee on Oil Pollution Research (ICCOPR), the Center for Offshore Safety, the International Regulators Forum, the Department of Energy, the new National Academy of Sciences (NAS) program funded by the BP settlement, and within the Bureau of Safety and Environmental Enforcement (BSEE) itself. The Committee considered the benefits of avoiding duplication of effort among new and existing entities, and the availability of resources and technical expertise to support proposed activities. As a result, this recommendation focuses on creating an Institute that will assist BSEE by taking a leadership role in ensuring collaboration among the various entities addressing offshore safety and in addressing critical gaps in offshore safety research.

In keeping with this approach, the recommended role for OESI focuses on research, analysis, and collaboration surrounding offshore safety and environmental management. The OESC Subcommittee on Spill Response reviewed the topic of oil spill response research and development, and has concluded that there are adequate structures already in place that were created by the Oil Pollution Act of 1990, namely the ICCOPR. The purpose of ICCOPR is to coordinate a comprehensive program of oil pollution research and technology development among Federal agencies, in cooperation and coordination with industry, academia, research institutions, state governments, and other nations, and to foster cost-effective research mechanisms, including joint agency funding of this research. The Spill Response Subcommittee recommended that the Ocean Energy Safety Institute should avoid duplicating ICCOPR's efforts in this area.

The recommendation outlined below is designed to afford DOI/BSEE flexibility in building OESI. The recommendation is scalable, allowing OESI to evolve as resources become available and additional priorities are identified. The recommendation also attempts to be responsive to issues raised by OESC membership, including:

- Ensuring coordination with existing entities with a significant role in offshore safety
- Minimizing duplication of effort and competition for scarce expertise
- Providing a defined role in research and development, but not one that undercuts other research programs
- Providing a home for those OESC recommendations that would benefit from diverse technical oversight for implementation.

The Ocean Energy Safety Institute

Structure

OESI would be established by contract, funded by BSEE, and report to the Director of BSEE. The Institute would be located at an existing institution (e.g., a National Lab or university), selected through a competitive request-for-proposal (RFP) process, and the contract would be re-competed every several years. A relatively small number of BSEE staff, co-located with OESI, would serve as liaison between OESI and the bureau, overseeing the contract, facilitating meetings and workshops, and ensuring that OESI and BSEE priorities are integrated.

As discussed below in the section Role of OESI, the winning institution would be responsible for managing OESI, managing the process of setting yearly objectives, conducting certain work to further the attainment of those objectives, and being a focal point for collaboration on issues within the OESI mandate.

A significant challenge in creating the Institute will be to establish a structure that encourages an institution with appropriate expertise to compete for the role of host, without then being unduly restricted in conducting the type of research that made it an attractive candidate to host OESI. The Committee believes that the winning institution should not be the exclusive recipient of research and other funding from BSEE or other sponsors. Other institutions with relevant expertise should be able to compete for research and other grant opportunities. Likewise, the other divisions of the host institution, as a pre-existing entity with expertise in safety-related matters, should be able to compete for projects from other sources. However, this could create an appearance of a conflict of interest, in which the OESI component of an institution is helping to set priorities for research projects for which other components of the institution may compete. BSEE will need to establish a firewall between OESI, which manages projects on BSEE's behalf, and the rest of the host institution that competes for research funding. The firewall should be clearly addressed in the RFP, as potential competitors will want to know of any such mechanisms before deciding whether to bid. Other aspects of this recommendation also help to mitigate this potential conflict issue, including a governance board (see next section) that provides independent oversight of OESI, and the requirement to re-compete the contract every several years. The re-competition of the OESI contract would both provide an opportunity for BSEE to make adjustments to the program and create an incentive for host institutions to treat research competitors equitably since the roles could be reversed in the future.

Additionally, the RFP should address patent and other issues pertaining to the relationship between the host institution, OESI and any corporate or non-profit entity that might be created or spun off as a result of funded research.

Governance

As noted above, OESI reports to the Director of BSEE, and would be subject to the usual oversight that comes with a government contract. However, to meet the Secretary's objectives for collaboration and leadership in offshore safety and environmental management, the Committee recommends the creation of a governance board/steering committee for OESI. The role of this board/committee would include:

- Helping to build OESI and develop its strategy, detailed mission statement and initial objectives.
- Once established, providing strategic and technical guidance to OESI.

- Facilitating exchanges between various entities working in OESI subject areas to minimize duplication and identify opportunities for collaboration.
- Facilitating dissemination of OESI results and recommendations to the user community (industry, local/state/Federal agencies, academia, etc.)

The board/committee should consist of both permanent and rotating members. Certain organizations with a fundamental and ongoing role in promoting offshore safety should have permanent representation on the Board. Such organizations include: BSEE; the host institution; the Center for Offshore Safety, the Department of Energy, the U.S. Coast Guard, and the National Academy of Engineers (both for its own expertise and representing the new NAS program mentioned above). Rotating members would be individuals with appropriate expertise representing industry (including major and independent operators, drilling contractors and Engineering, Procurement and Construction contractors), academia, government labs, non-governmental organizations and other centers of expertise – both domestic and international – on subjects relevant to OESI's mandate.

Role of OESI

Consistent with the Secretary's vision, OESI would facilitate research and development, training, and implementation of operational improvements in offshore drilling safety. While this is a broad mandate, this Committee, through its past recommendations and ongoing work, has identified gaps in existing processes and programs, discussed below, that would benefit from an entity such as OESI as a focal point for implementation. OESI's role would be expected to evolve over time as OESI, its governance board, and BSEE identify other priorities.

- *Research and Development*: Roles for OESI would include:
    - Develop and maintain a technology R&D roadmap – Through a collaborative, multi-agency and stakeholder process, OESI would identify, solicit, and prioritize research topics and potential sources of funding. The roadmap would provide guidance to relevant federal research institutions to ensure that those institutions are conducting or funding research that is relevant to BSEE's challenge of ensuring that regulations mitigate risks that have been appropriately quantified.
    - Help ensure that safety technology is keeping up with drilling and production technology.
    - Regularly conduct gap analyses on key technologies.
    - Provide forums for ensuring that research results are disseminated.

  On behalf of BSEE, the OESI should facilitate coordination with other federal agencies that have ongoing research and development programs which are relevant to safe offshore exploration and production. To illustrate, the Department of Energy (DOE) sponsors research and development that is relevant to the challenge of scientifically quantifying risks associated with offshore exploration and production activity. Historically, DOE has collaborated with BSEE to guide priorities and select research topics. The OESI should formalize this relationship by establishing and leading sustainable interagency cooperation. This will ensure that DOE is focused on the research that is most directly relevant to BSEE's regulatory mission.

The Committee recommends that research be managed in a similar manner as Deepstar, which manages its research through the use of sponsor groups that oversee each research topic. These sponsor groups consist of industry, government and other stakeholder groups.

- *Best Available and Safest Technology*: In his letter of August 10, 2012, BSEE Director James Watson asked the OESC to provide guidance on how to best stimulate private sector interest and investment into BAST, as well as a procedure to determine BAST on a rolling, real-time basis. The OESC's Spill Prevention Subcommittee has prepared a recommendation for implementing BAST that includes a specific role for OESI to facilitate the BAST process, including building on OESI's roles in prioritizing research and identifying gaps discussed above. A BAST recommendation was approved by the full Committee in its January 2013 meeting.

- *Collaboration/communication*: OESI would sponsor and facilitate the Offshore Safety Leadership Council recommended by OESC (see "Safety Culture" recommendation approved by OESC at its April 26, 2012, meeting), and similar efforts for leadership communication and collaboration. It would also develop and host workshops relevant to the OESI mandate, such as the containment workshops recommended by OESC (i.e., Workshop on Organizational and Systems Readiness for Containment Response, approved at the April 26, 2012, OESC meeting). Other workshops would focus on technical issues, such as oil and gas development in frontier areas (e.g., the Arctic OCS, ultra-deepwater drilling, high-pressure and high-temperature reservoirs). Through these workshops, OESI would facilitate collaborative problem solving.

- *Data Management & Analysis*: There's a general consensus on the need to report certain types of data (e.g., incidents, near-misses), develop and report performance measures, and analyze the data to identify trends and issues. The OESC previously recommended work related to safety culture performance indicators (i.e., "DOI/BSEE should put greater emphasis on measuring the health of the safety culture by requiring the reporting of safety performance indicators," approved by OESC at its August 29-30, 2012, meeting). Other groups, such as the Center for Offshore Safety and the International Regulators Forum, also are working on performance measurement issues. To the extent that there are gaps in these efforts, or a need for additional coordination or independent analysis, OESI could help to facilitate development of performance measures, develop/host data storage and management tools, and analyze data.

- *Training*: BSEE has established a National Offshore Training Program (NOTP) to provide ongoing training and development for its staff. However, in keeping with one of the Secretary's original goals for the Institute to help develop a cadre of technical experts throughout government and industry, there are potential roles for OESI to augment the NOTP. One possible role would be to periodically review BSEE's training programs and recommend adjustments to ensure that they are in line with new technological developments and requirements. The OESI could also carry out specialized training for non-BSEE personnel to ensure that a broad base of technical expertise exists throughout the government, as may be needed during oversight of future well-control events. OESI could also supplement the regular curriculum through professional development opportunities and special training of BSEE and other personnel related to "leading edge" research being conducted through the Institute.

Summary of Recommendation

The Department of the Interior should establish an Ocean Energy Safety Institute, reporting to the Director of BSEE, through a competitive request-for-proposal process that is repeated every several years. The Institute would support BSEE's missions regarding offshore safety and environmental management through various means, which may include:

- research and development, including development and maintenance of a technology research and development (R&D) roadmap and dissemination of research results;
- facilitating a new BAST process;
- facilitating communication and collaboration among entities involved in offshore safety and environmental management through workshops and other methods; and
- other topics as may be identified in the future.

BSEE should establish a board or steering committee consisting of relevant government agencies, industry, academia, non-governmental organizations, and other centers of expertise that would help to develop the OESI's initial goals and strategies, and provide ongoing strategic and technical advice to the Institute.

Note: The foregoing paper should be attached to any transmittal of this recommendation to provide the context for and details of the recommendation.

Enclosure 6

Ocean Energy Safety Advisory Committee: Recommendations on Oil Spill Prevention, Safety, Containment and Response on the U.S. Arctic Outer Continental Shelf

A) Background

Oil and gas potential is significant in Arctic Alaska, with renewed interest in oil and gas exploration and production in the Beaufort and Chukchi seas of the Alaska Outer Continental Shelf (OCS). Beyond petroleum potential, this region also supports significant fish and wildlife resources and ecosystems, with indigenous people who rely in large part on these resources for their way of life.

A key concern about development of oil and gas resources in the Arctic OCS is the need to ensure that scientific understanding and technological capability are sufficient for reliable oil-spill risk assessment, and safety, prevention, containment and response under difficult and rapidly evolving environmental conditions in areas with limited local infrastructure.

Challenging environmental conditions in the Arctic Ocean require fit-for-purpose technological responses and regulatory approaches. There is potential for severe weather including high winds, dense fog and sub-zero (F) temperatures that can persist for weeks at a time. Most importantly, seasonal sea ice has the potential to cause operational difficulties during drilling as well as capping, relief well operations and other source control activities. Spill response on the U.S. Arctic OCS requires continued development and implementation of technologies for detecting, monitoring, and tracking oil around and under ice, and enhancing the efficacy of oil spill countermeasures that could be used in Arctic waters, such as mechanical recovery (e.g., skimmers), in-situ burning, bioremediation, and dispersants.

The Chukchi and Beaufort seas and shoreline are remote and lack basic infrastructure. Equipment and specialized personnel cannot easily be brought in during adverse weather conditions and vast transportation distances can result in long or delayed delivery times. These conditions have required operators to properly design their drilling, safety, source control and oil spill response programs to account for accessibility and ensure prompt delivery of equipment, replacement parts and skilled personnel.

Drilling and other offshore facilities must be properly designed for safe operations that account for adverse weather and lack of accessibility. Although exploratory drilling will only take place offshore during the short open-water season, sea ice can still be present. Additionally, this exploration can lead to year-round development operations and eventually production. Production facilities need to be engineered with sufficient strength to withstand the force of moving pack ice and Arctic pipelines will need to be protected from ice gouging, scouring and permafrost thaw. The Arctic Ocean's challenging environment requires robust and potentially new or enhanced standards to ensure safe, effective, and consistent operations.

Certain containment and source control equipment designed for temperate waters are not technically suitable for Arctic conditions. Capping stacks, capture devices and associated collection systems must be properly designed to account for adverse weather, lack of accessibility and the need for prompt delivery of equipment and associated trained personnel. For example, in shallow water ice scouring may prevent use of capping stacks and domes during some times of the year, unless these devices are specially designed to operate below scour depth. Also, seasonally limited access and icing conditions can decrease the time frame during which relief wells can be drilled. A rig that can be used for drilling a relief well should be identified and located in the same general operating area to ensure prompt deployment in response to a blowout or other loss of well control. The identified relief well drilling rig should be designed to operate in ice and adverse Arctic weather conditions, as appropriate.

Safety management systems for the Arctic are not any different than other oil and gas operating areas in the U.S. OCS. However, severe environmental conditions in the Arctic OCS introduce additional safety and human factor challenges, for example related to weather exposure, difficult and time-consuming crew changes, and large variations in duration of daylight between summer and winter. While the current Safety and Environmental Management System (SEMS) regulations are definitely applicable to operations in the Arctic, this difficult operating environment will require some Arctic-specific work practices, technologies and operating procedures and/or support mechanisms.

On arriving at the recommendations presented below, the Ocean Energy Safety Advisory Committee (OESC) drew upon the knowledge of its own members, consulted with experts in the field, and reviewed and analyzed a number of sources, including:

- U.S. Coast Guard's (USCG) Incident Specific Preparedness Review.
- National Oil Spill Commission's report.
- National Energy Board review for offshore drilling in the Canadian Arctic.
- U.S. Geological Survey Circular 1370, Science issues pertaining to energy development in the Arctic OCS.

The OESC initially considered assessing current Arctic oil spill prevention, containment and response technologies to identify gaps. However, after consideration of the rapidly evolving nature of exploration and production technologies and procedures relevant to Arctic waters, the OESC decided to narrow the scope and focus its recommendations on regulations and standards. Arctic standards should be part of an overall regulatory framework for operations in the U.S. Arctic OCS.

B) Specific Recommendations

1. ***To ensure common standards for Arctic OCS exploration and production, the OESC recommends that DOI develop Arctic-specific regulations and /or incorporate standards for prevention, safety, containment and response preparedness in the Arctic OCS*.**[1]

Although some existing regulations and national Notices to Lessees (NTL) are applicable and sufficient for Arctic activities, BSEE regulations as written do not specifically address all the Arctic operating conditions. In particular, to ensure full system readiness for Arctic OCS exploration and production, BSEE/DOI (in coordination with other agencies, as appropriate) should do the following:

a. Spill Prevention - 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.

b. Safety Management - 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.

c. Spill Containment - 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.[2]

d. Spill Response – review Oil Spill Response Plan (OSRP)[3] ***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.***

In particular, OSRP regulations and associated permitting regulations and approvals should address at least the following elements:

i. Seasonal drilling limitations that consider the timing and adequacy of oil spill response operations, given available technologies and type of drilling operation.

ii. Prompt deployment of response equipment and adequately trained personnel.

iii. Ice capable equipment appropriate for expected conditions.

iv. Adequate strategies and equipment to protect important ecological and subsistence areas that could potentially be impacted by an off-shore oil spill.

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[1] This recommendation was approved by the OESC and forwarded to BSEE Director Watson on 15 October 2012. The following recommendations (a – d) are intended to expand upon this previous recommendation.

[2] The OESC defines all operations intended to control oil spills at their source as part of containment. Thus, the term containment as used here includes deployment of capping stacks, domes, relief wells and related source control operations.

[3] Oil Spill Response Plans are documents prepared by an operator and approved by BSEE describing how that operator would respond to an oil spill in a specified region, including detailed descriptions of equipment, personnel and procedures that could be used in response operations.

2. *BSEE in coordination with the U.S. Coast Guard, Environmental Protection Agency, and Pipeline and Hazardous Materials Safety Administration, should review and assure the adequacy of Oil Spill Removal Organizations for the Arctic OCS.*

In the aftermath of the Exxon Valdez spill and the Oil Pollution Act of 1990, the U.S. Coast Guard (USCG) began classifying Oil Spill Removal Organizations (OSROs) to better validate the capabilities and suitability of companies providing response resources listed in industry response plans that are regulated by the Coast Guard. While the planning requirements within these industry response plans are mandatory for the owners and operators of vessels and facilities, the classification of response companies as OSROs, and the inclusion of their equipment in the national Response Resource Inventory (RRI), both remain voluntary programs administered by USCG. The USCG conducts periodic inspections to verify the equipment listed by an OSRO meets the requirements of their classification status, including both the material condition of the equipment as well as its suitability for the intended operating environment (such as the offshore environment). BSEE conducts similar inspections to ensure an OSRO's equipment and personnel meet industry planning requirements contained within OSRPs.

The USCG OSRO classification program is presently not climate specific and as a result has no requirements specific to the Arctic or other cold climate operating areas, or any requirements for specific equipment capable of oil recovery in icy conditions. In Alaska, there are several OSROs that respond to spills in the Arctic, namely Alaska Chadux Corporation (ACC), Alyeska, and Alaska Clean Seas (ACS). ACC is a small OSRO that responds to vessel or onshore facility spills throughout Western Alaska. Alyeska responds to inland spills that occur from the Trans-Alaska Pipeline. ACS, until recently, has been focused on responding to spills from inland and near-shore oil exploration and production activities. With resumed offshore oil drilling in the Arctic, ACS has been further outfitted to respond to offshore oil spills in the Arctic OCS to supplement response equipment and personnel being provided by drilling companies. It is important that BSEE continue to closely monitor and inspect the response equipment and personnel listed in OSRPs to ensure their suitability for use in the Arctic operating environment. Furthermore, it is important for BSEE to support any USCG review of their OSRO classification process for those entities that operate in the Arctic OCS, and coordinate any changes to equipment requirements or inspection protocols that may be necessary to ensure OSROs are adequately equipped and manned for Arctic conditions. It is recommended that BSEE collaborate closely with the USCG, Environmental Protection Agency (EPA) and the Pipeline and Hazardous Materials Safety Administration to share information and establish common expectations, consistent requirements, and coordinated inspection regimes for OSRO equipment and personnel that will be used to respond to spills in the Arctic OCS Environment.

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

Regulations at 30 CFR 254 require that a response plan must demonstrate that an operator can respond quickly and effectively whenever oil is discharged from one of their facilities. Critical to achieving this goal is the condition and operability of response equipment and the skill sets of crews whose jobs are to deploy and operate such equipment safely and to its maximum potential. Regulations at 30 CFR 254 provide for exercises, training, and inspections to validate that equipment is being maintained and that it can be deployed quickly when called upon. Specifically, these regulations require or allow for:

a. Annual deployment exercises for response equipment staged at onshore locations.
b. Semi-annual deployment exercises using response equipment staged on offshore facilities or on dedicated vessels.
c. Unannounced exercises that can include field deployment of equipment.
d. Annual equipment inspections that can include in situ operation or field deployment of equipment.

During a single required deployment exercise, the plan holder, based upon current regulations, need not deploy each piece of equipment in their inventory. Each type of equipment, however, does need to be deployed over a specified time period during hands-on training.

As the Arctic is a frontier area and response equipment that is listed in both proposed and approved OSRPs may be largely new or may not have been subject to inspection by BSEE, the OESC recommends that BSEE evaluate the need to require deployment of categories of response equipment listed in an OSRP that have not yet been successfully deployed, in advance of the initiation of drilling operations where such equipment might be used.

4. DOI should enhance its engagement with other agencies and stakeholders, including the Alaska Regional Response Team and 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.

The federal government and State of Alaska developed a Unified Plan titled "Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases". This Unified Plan is divided into ten subarea planning regions, and the arctic region is contained in the North Slope Subarea Contingency Plan (SCP). The SCP supplements the Unified Plan and describes the strategy for a coordinated federal, state, and local response to a discharge or substantial threat of discharge of oil or a release of other hazardous substance from a vessel, offshore or onshore facility, or vehicle operating within the boundaries of the North Slope Subarea. The SCP is used as a framework for establishing response mechanisms. Any review for consistency between government and industry plans should address the recognition of special economic and environmentally sensitive areas and related protection strategies, as well as identify potential needs in response personnel and the quantity and type of equipment available within the area (including federal, state, and local government and industry) in comparison to probable need during a response.

OSRP requirements are found in federal regulations under 30 CFR 254, which in general contains the federal regulatory requirements for facilities located seaward of the coast line. Sections pertinent to this recommendation include 254.4, which allows OSRPs to reference other documents such as the National Contingency Plan (NCP), Area (or Subarea) Contingency Plans, BSEE or BOEM environmental documents, and OSRO documents. For the Arctic OCS, OSRPs must be consistent with the SCP.

Since OSRPs and the SCP contain important but different information, it is important for DOI to work with other agencies and stakeholders, through participation in the Alaska Regional Response Team (ARRT), to increase their engagement in updating the SCP as well as supporting the public engagement process, especially in reaching out to local communities. Ongoing consultation with tribes and local communities could provide important information to planners with regard to environmental sensitivities and raise preparedness awareness. Without this input to planning, the ARRT may not have the needed expertise or focus on critical issues related to exploration and drilling offshore.

DOI should ensure that all of its Bureaus with expertise and/or responsibilities in the Arctic contribute to the SCP process through the DOI representative on the ARRT. As the responsible agency for reviewing OSRPs, BSEE can provide the ARRT with specific information that would be critical to response personnel. Likewise, other Bureaus and Offices within DOI can ensure that their expertise in the offshore environment can be brought to discussions of risk and sensitive environments.

Increased participation in the ARRT will also assist BSEE in continuing to ensure that Arctic OSRPs are consistent with the SCP. BSEE can work with other ARRT members to ensure that the SCP has scenarios that are updated or developed that are applicable to the existing and proposed exploration and production activities in the offshore environment.

5. BSEE should formalize a process with a fixed timeline for interagency review of Arctic Oil Spill Response Plans (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.

OSRPs are required for BSEE-regulated facilities in both federal and state offshore waters (30 CFR 254). These plans provide detailed information on how an operator will respond to oil spills, including those categorized as a worst case discharge, and must conform to oil spill response requirements stipulated in applicable Area (or Subarea) Contingency Plans. These OSRPs, including those prepared for operations in the Chukchi and Beaufort Seas, must be approved by BSEE's Oil Spill Response Division. Although the OSRP approval process resides with BSEE, they may provide these plans for review by other federal agencies as described in Memorandums of Agreement signed by these agencies. Depending on the location, states may have jurisdiction and would conduct their own review.

For recent operations in the Beaufort and Chukchi Seas, an interagency review process was initiated to provide for additional reviews of OSRPs by the USCG, EPA, National Oceanic and Atmospheric Administration, and other federal agencies that have expertise relevant to preparedness and oil spill response in the offshore environment. This interagency review was implemented to ensure a robust and coordinated review process in light of lessons learned from the Deepwater Horizon incident, given the controversy and unusual challenges associated with responding to an oil spill in the Arctic OCS. To ensure the fullest examination of issues regarding exploration and production in the Arctic OCS, the OESC recommends that this interagency review process for Arctic OSRPs be continued.

The OESC supports recent BSEE actions to make redacted versions of approved Arctic OSRPs freely available to the public, wherein parts of the plan have been withheld to protect proprietary or confidential information. This will ensure that the public and other stakeholders remain fully aware of the level of containment and response preparedness capabilities in the Arctic OCS and how elements of the SCP are being implemented in Arctic OSRPs. The OESC also debated the pros and cons of public review of Arctic OSRPs prior to approval, but could not come to agreement on a recommendation.

6. If the charter of the Ocean Energy Safety Advisory Committee 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.

With Arctic OCS oil and gas development likely in the years to come, DOI/BSEE will encounter new scientific and engineering issues related to the Arctic's challenging operating environment that may require BSEE to adopt Arctic-specific standards and regulations. One way for BSEE to obtain early and ongoing multi-stakeholder input would be through continuation of the Arctic Subcommittee of the OESC. The intent of this continued Subcommittee would be to address technical and regulatory issues needed to improve safety in offshore and related operations and protect marine ecosystems and nearby coastal areas.

C) Linkages to Other Recommendations from the Ocean Energy Safety Advisory Committee

In addition to the recommendations presented above from the OESC Arctic Subcommittee, other recommendations already made to DOI/BSEE by the OESC or under development by other OESC Subcommittees are also highly relevant to the Arctic OCS operating environment. Although most OESC recommendations will help improve Arctic OCS safety to some degree, for illustrative purposes we highlight below those recommendations that are particularly important in ensuring the safe and environmentally responsible development of oil and gas resources on the Arctic OCS.

Spill Prevention Subcommittee (SPS) Recommendations: Completed and in Progress

As part of Vector 1, six recommendations have already been endorsed and submitted by the OESC regarding technology needs to improve spill prevention capabilities in the OCS. These recommendations pertain to improved capabilities for early kick detection, monitoring wellbore conditions below the wellhead, enhanced BOP shearing capabilities, real-time BOP monitoring, acoustic activation technologies for remote BOP control, and improved BOP/remotely operated vehicle (ROV) interfaces and functionalities. All six of these recommendations have application and relevance to well operations in the Arctic OCS, particularly as related to remote monitoring of wellbore conditions and BOP status given the potential for disconnects from the well during drilling due to sea ice movement and the temporary abandonment of wells between drilling seasons. Also, due to the shallow water depth in much of the Arctic OCS and the resulting requirement to situate the BOP below ice scour depth, the functional requirements for acoustic activation and improved BOP/ROV interface technologies might need to be amended for operation in the Artic.

Although still in progress, Vector 2 from the SPS expands on some of the technology gaps identified in Vector 1 and identifies a need for development of an automated well safety system that would significantly improve the chances of detecting and safely responding to well influxes or "kicks." This work has direct application to Arctic OCS operations, especially given the difficult environmental conditions that might complicate and/or delay current well control response capabilities.

The remaining effort (Vector 3) being progressed by the SPS deals with the process for facilitating identification, review, availability and implementation of Best Available and Safest Technologies (BAST) for spill prevention in the U.S. OCS. Given the challenging conditions in the Arctic and the frontier nature of oil and gas operations there, this process for BAST could be particularly beneficial for the industry and regulators in ensuring the safety of offshore Arctic oil and gas operations.

Spill Containment Subcommittee (SCS) Recommendations: Completed and in Progress

The work on Vector 1 by the SCS resulted in a recommendation by the OESC that DOI/BSEE conduct a workshop on organizational and system readiness for containment response based on lessons learned from source control efforts during the Macondo Well (Deepwater Horizon) blowout. While this workshop would focus on reviewing past containment efforts in the Gulf of Mexico (GOM), path forward discussions at the workshop could also address special challenges posed by the need for timely and effective management, coordination and oversight of source control efforts in the Arctic OCS.

While the remaining two SCS Vectors (i.e., assessing and mitigating risks posed by underground blowouts and broaches; and containment scenario planning, considering non-cappable blowouts) are still being progressed, both have applicability to the Arctic OCS. Although well pressures are expected to be lower in the Arctic OCS than in the GOM, the geomechanical behavior of sub-sea-floor permafrost and hydrate layers in shallow Arctic waters may need to be addressed when assessing underground blowouts and geologic containment. Regarding scenario planning, the environmental conditions in the Arctic OCS may limit the applicability and effectiveness of containment options (i.e., capping stacks, domes and relief wells) available in the deepwater GOM. However, lower reservoir pressures in the Arctic OCS may offset some of these increased logistical and technical challenges.

Spill Response Subcommittee (SRS) Recommendations: Completed and in Progress

In addition to the new Arctic-specific spill response recommendations made earlier in this report, twelve SRS recommendations were endorsed and submitted by the OESC to DOI/BSEE from the August 2012 meeting. These recommendations were generic to spill response issues throughout the U.S. OCS and are thus directly applicable to the Arctic OCS. Of particular relevance to the Arctic OCS are recommendations that DOI: i) support continued and dedicated R&D funding and facilities for oil spill response research and develop a R&D strategic plan to address various OCS operating conditions, including those encountered in deep water and in the Arctic, and ii) continue to monitor activities of international organizations, especially in the Arctic to ensure that BSEE's regulations and policy related to planning, preparedness and response can adapt to new information as Arctic oil exploration increases around the world.

Safety Management System Subcommittee (SMSS) Recommendations: Completed and in Progress

The previous work on Vectors 1 and 2 by the SMSS regarding safety culture improvement and optimizing safety management systems, respectively, is generally germane to the Arctic given the focus on safety leadership improvement and enhancement of the current SEMS regulations. As such, all seven of the SMSS recommendations endorsed and submitted by the OESC to DOI/BSEE are directly applicable to the Arctic OCS. However, the operating and environmental conditions in the Arctic may present additional challenges when considering audit protocols and may require some Arctic-specific safety performance indicators. The remaining work being progressed on Vector 2 by the SMSS addresses additional improvements or enhancements to the current SEMS regulations that are pertinent to the entire US OCS, including the Arctic.