Effects of Water Depth Workshop

BSEE
Bureau of Safety and Environmental Enforcement

SAN LUIS HOTEL
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Argonne NATIONAL LABORATORY

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Session 3: Well Drilling & Completion Design and Barriers
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Session 6: Risk Assessment of Critical Operations and Activities
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Recorder Acknowledgements

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Administrative Staff Acknowledgements

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Ms. Kristen Lambert set up the accounting, handled all of the funding, assisted with the registration, assisted with the photography, disbursed funds, and provided help on a wide variety of last minute items.

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Effects of Water Depth on Offshore Equipment and Operations

Executive Summary

On November 2-3, 2011, nearly 140 subject matter experts from the offshore oil and gas industry and federal regulatory agencies, assembled to discuss the "Effects of Water Depth on Offshore Equipment and Operations." This workshop, referred to as the Effects of Water Depth (EWD) Workshop, was sponsored by the Bureau of Safety and Environmental Enforcement (BSEE) in part to respond to a recommendation made by the Outer Continental Shelf Safety Oversight Board (OSOB) in their September 1, 2010 report to the Secretary of the Interior, Ken Salazar. Specifically, the recommendation was to "consult with technical experts, conduct further analysis of the effects of water depth on equipment and operations, and determine the adequacy of current regulations."

In the eighteen months since the Macondo incident of April 20, 2010, both industry and regulators have worked diligently to understand the events leading to the incident and to implement steps to prevent recurrence. To further this effort, BSEE designed the EWD workshop to draw the offshore drilling arena's foremost technical subject matter experts in order to collaborate and share their views and recent learning experiences specific to deepwater drilling technical challenges and issues. This included discussion of the need for revised and/or new regulations and industry standards to improve drilling, well control, and oil spill response operations. The EWD Workshop was also the first major public meeting of the newly formed BSEE organization since inception on October 1, 2011, and enabled the agency to publically provide its near-term vision as well as to foster technical communication with the industry.

In preparation for the workshop, BSEE brought in Argonne National Laboratory (ANL) as a neutral party to assemble and chair the steering committee and to conduct the workshop. The Steering Committee consisted of key leaders from BSEE, the oil and gas industry, and ANL who developed the workshop program and engaged additional subject matter experts to create six focused "White Papers." These papers formed the basis for the six Breakout Session discussions listed below:

1. *Well Control with Surface Blowout Preventers* (led by Brian Skeels)
2. *Well Control with Subsea Blowout Preventers* (led by Frank Gallander)
3. *Well Drilling and Completion Design and Barriers* (led by Jim Raney)
4. *Pre-incident Planning, Preparedness, and Response* (led by Alan Summers)
5. *Post-incident Containment and Well Control* (led by Holly Hopkins):
6. *Risk Assessment of Critical Operations and Activities* (led by Dan Fraser)

The two-day workshop consisted of an introductory plenary session followed by two four-hour technical breakout sessions, and a final plenary session to report the findings from each breakout group. Michael Else of BSEE hosted the plenary sessions that set the foundation for the workshop. Speakers included Michael Saucier, BSEE; David Miller, API; Steve Kropla, IADC; and Dan Fraser, ANL.

This executive summary offers the major findings from the EWD workshop. A complete summary of the workshop findings and undertakings are summarized in the body of this report with additional information available for a limited time on BSEE's website at http://tiny.cc/8s6g2.

One of the primary lessons learned from the Macondo incident is that existing incident command mechanisms did not fully anticipate the level of subsea containment challenges and their technical complexity. **It is recommended** that government regulators develop improved organizational structures, definition of responsibilities, and incident command functioning for a major subsea containment event. This improved 'command structure/ infrastructure' should include government & industry with pre-defined roles & responsibilities and include enhanced cooperation/collaboration between the USCG, BSEE, the E&P industry, and other stakeholders.

Greater collaboration is recommended between the offshore regulators (BSEE, USCG, EPA, NOAA, FWS, etc.) to reach agreement and develop guidelines for clean-up and response practices, particularly in the use of subsea dispersants and the burning of hydrocarbons. A **related recommendation was made for** the US to perform Norwegian style oil-on-water spill, response and clean-up exercises. Such controversial, yet effective, exercises would demonstrate and utilize all aspects of ICS communications and training as well as the industry capabilities for managing spill events. Workshop participants recommended that regulators continue to meet on a regular basis in order to maintain a high level of communication and coordination necessary to timely resolve these and other practices expected to better prepare and respond to future large-scale incidents.

The Workshop provided an opportunity to improve the understanding of the current regulatory requirement for wellbores to be designed to contain a Worst Case Discharge

(WCD) blowout. The view by many was that depending on how NTL No. 2010-N10 is interpreted, this could significantly change the way that all deepwater wells are designed. These new designs could bring other unintended consequences, such as: higher operational risks; operating inefficiency; and limitations on operational capability. Workshop discussion in this area led to a **recommendation for** more discussion between the industry and regulator prior to and after NTL releases to help ensure that the industry understands the rules and can provide important feedback for further regulatory developments.

Workshop attendees had the opportunity to discuss risk management directions for the future. Incident reporting turned out to be a major topic. Although the BSEE organization (and predecessors) requires reports to be filed for offshore "incidents" there is no such data gathering for "near misses". Comparative analysis from other industries has largely demonstrated that "near misses" follow many of the same precursors that lead to incidents and a proper analysis of such data would be highly beneficial for reducing the number of incidents.

On a related note, it was recognized that incident data reports currently being gathered need to be sorted, categorized, and analyzed manually – a time consuming and error prone process. **It is recommended** that BSEE work with industry to develop a strategy and standardized reporting data format for gathering data on both incidents and near misses. The standardized format should allow for computerized data analysis to be the primary method used for transforming the data into information.

Technical issues involving Blowout Preventers (BOPs) and remotely operated vehicles (ROVs) have been intensely studied by the industry for establishing recommended practices (RPs) that improve safety, especially in the past eighteen months. Through industry coordination, the agreed upon changes have been incorporated into API Standard 53, including new definitions and language proposed for inclusion into the CFRs. EWD workshop participants discussed the many changes to industry RPs and to related Federal regulations, as well as over twenty-five specific technical issues involving BOPs and ROVs. From these discussions, workshop participants **recommended** coordinated efforts toward standardization of ROV interfaces to allow greater success during post incident emergency response and for BSEE to review and respond to the industry's recent standards development proposals.

Surface Blowout Preventers (SBOPs) are easier to operate and maintain than subsea BOPs and should be strongly considered for TLPs and SPARS that are attached to the ocean floor and designed to withstand a 100-year storm. They are not suitable for floating rigs since they cannot be retrieved fast enough in the face of a hurricane. **It is**

recommended that the Industry develop SBOP specific guidelines for use in planning and implementation of SBOP operation that offer examples for specific circumstances such as the use of dual riser technology as well as provide exceptions for individual operator requirements.

In general, session participants recognized that as a result of the Macondo accident, the BSEE (the primary federal offshore regulatory body) received a considerable amount of external criticism that they were “too close” to the industry. In response to this criticism, communication channels have been significantly reduced. **A consistently overriding finding** from multiple sessions of the workshop is that more communication, not less, between regulator and industry would be highly beneficial toward safe offshore operations. There is a high level of respect between industry and regulator; both regulators and industry have contributions to make toward improving safety; and combined efforts are a significant improvement over working in isolation.

Workshop participants all seemed to agree that the workshop was highly beneficial and that they look forward to ongoing communication of this kind between regulators and industry experts.

Introduction to Technical Summaries

Technical Summaries from the Effects of Water Depth Workshop – November 2-3, 2011

The following materials comprise summaries of the six technical breakout sessions held at the Galveston 2011 Workshop on the Effects of Water Depth on Offshore Equipment and Operations.

ORGANIZATION

During the early stages of organizing the Effects of Water Depth (EWD) Workshop and with the advice of the Bureau of Safety and Environmental Enforcement (BSEE) and oil industry technical societies (American Petroleum Institute (API), the Offshore Operators Committee (OOC),and the International Association of Drilling Contractors (IADC)), Argonne National Lab (ANL) sought technical experts from the various organizations and companies actively involved with deepwater drilling in the Gulf of Mexico. From these early discussions, a broadly based Steering Committee was formed, consisting of people actively involved with the development of industry standards, regulations, and good practices in the technologies of deepwater drilling, well control, and oil spill response. This group had both the technical and personal knowledge necessary to identify the critical issues for discussion at the workshop and select the speakers and other experts who could contribute most to workshop content and proceedings.

The timing, location and duration of the workshop were addressed early in the process, and decided that a short two day workshop in the Houston area would be the most effective and easiest to attend. Further, the steering committee wanted to avoid the hurricane season in the Gulf, since a major hurricane would quickly divert attendees with responsibility for deepwater drilling and well control from the workshop to the rigs operating in Gulf waters, thus the decision to hold the workshop in early November.

CONTENT

The next question that the steering committee addressed was how to handle all of the differing topics of interest. Rather than offering a conference style format with presenters and audience members, the decision was made to hold the event as a workshop, where participants could openly contribute and discuss ideas and experiences. It was decided to separate the workshop into multiple simultaneous sessions so that experts on each topic could talk at length about specific issues. Eight to ten hours could be dedicated to each topic. To improve efficiency, the Steering

Committee agreed to prepare and provide a technical “white paper” for each topic in advance to help prepare the participants for discussion on the specific issues.

Six topics were identified with Steering Committee members volunteering to organize and prepare white papers in preparation for the breakout sessions. Given their understanding of the purpose of the workshop as committee members and knowledge gained during development of the white papers, the organizers of the six white papers were also selected to chair of the six Technical Breakout Sessions during the workshop. The six sessions and Chairpersons were:

1. Well Control with Surface Blowout Preventers (BOPs) – led by Brian Skeels of FMC Technologies Inc.
2. Well Control with Subsea BOPs – led by Frank Gallander of Chevron
3. Well Drilling and Completion Design and Barriers – led by Jim Raney of Anadarko
4. Pre-incident Planning, Preparedness, and Response at Different Water Depths – led by Alan Summers of Diamond Offshore Drilling Inc.
5. Post-incident Containment and Well Control – led by Holly Hopkins of API
6. Risk Assessment of Critical Operations and Activities – led by Dan Fraser of ANL

In preparing the white papers, the session chairs consulted with and included key industry experts who contributed to the writing efforts. BSEE established a web site to advertise the workshop, and the white papers were then made available on this web site to those interested in attending the Workshop.

The two-day workshop was designed to consist of an introductory plenary session involving four well-known and respected speakers followed by two four-hour technical ‘Breakout’ Sessions (each with its own set of technical speakers to further educate participants on the issues) and a final plenary session to report the findings from each breakout group. Each Breakout Session included a Chairperson, Co-chair, and Recorder (in some instances, the Co-chair also acted as Recorder) and included the necessary audio-video equipment and U-shaped seating configuration to allow participants to more easily see, hear and speak with the Chairs and other sessions participants.

In addition, graduate students from the University of Houston and Rice University were recruited to act a “recorders” of the sessions to compliment the general session recorder and contribute written content to the proceedings. In some cases this written content became part of a revised white paper or an addendum to the original white paper. The students also helped to prepare a set of slides that each session chair could use to summarize the findings and recommendations of the workshop at the plenary session held during the afternoon of the second day.

People interested in attending the workshop were asked to pre-select attendance for one of the six sessions. To manage the high level of discussion anticipated for each of the six technical sessions, the steering committee decided to limit participation to no greater that 25 subject-matter-experts (SMEs) per session. Due to strong interest for some sessions, that number was later revised to no more than 30 SMEs. Further, to ensure the highest quality of discussion during the workshop, all participants were required to apply on-line to BSEE's webpage and indicate a minimum level of experience and knowledge in order to qualify for participation.

ACTION

The following materials represent the Technical Summaries resulting from the six breakout sessions. In most cases, these summaries present a series of discussion items followed by recommendations, if any, made by the session participants, and suggestions about the relative importance of the issues, and who might take the lead on future actions.

Due to the variations in the white papers and character of the differing breakout sessions, the method by which the Session Chairs captured and reported their session's discussion and findings varied, thus the different reporting formats contained in this report.

Beyond the short summaries presented here, this report also provides the following:

- PowerPoint presentations made by the Initial Plenary Session speakers.
- Introductory PowerPoint presentations made by each session chair at the beginning of the technical Breakout Sessions.
- Additional PowerPoint presentations made by invited speakers at each session.
- Full text of the White Paper for each Session (either the revised final version, or the original version with addendums generated at the session).
- PowerPoint Slides that formed the Session Summary, presented at the Closing Plenary Session.
- Any other workshop information that may be relevant to the session.

Technical Summary of Workshop Session #1 – Surface BOPs

Session #1 of the Effects of Water Depth (EWD) Workshop held in Galveston TX on November 2 & 3, 2011, addressed the broad issue of surface blowout preventers (SBOPs) and their uses. The Session identified a number of areas where industry and regulators need to conduct further discussions to seek clarification or agreement on specific regulations or technical developments. Some of the comments from the session are presented below as questions and the answers presented suggest possible actions in the future. The following is a summary of the issues that were discussed in this session. More detailed text and discussion of these items are presented in the body of the white paper.

Item #1: Benefits of SBOPs

All of the delegates essentially agree with the pros and cons presented in the white paper. They agreed that moving the BOP from the seafloor to the surface simplifies well hydraulics and response time, as well as personnel training and operations.

However the overwhelming issue that trumps all others is the metocean criteria and the offshore facilities structural and mooring capability. Because their hull and moorings are designed to withstand the 100 year storm, Spars and TLPs are better suited to SBOP and drilling riser operations.

It was also noted that a SBOP/high pressure riser advantage is getting into tight (high well count) clusters beneath a Spar or TLP. Keeping the BOP at the surface helps to reduce these kinds of spacing issues.

In summary, SBOP drilling from a MODU is not recommended for US waters, unless it is demonstrated that the MODU could shelter in place to ride out a 100 year storm. Spars and TLPs, especially those with multi-well platforms are much better suited for SBOP/high pressure riser operations.

Item #2: It's All About The Riser

The primary technical limitation of SBOP drilling technology is the load management and metallurgical properties of the high pressure pipe necessary to connect the SBOP to the sea-floor well assembly. Because of the high pressure containment requirements below the SBOP, tapered stress joints are used to deal with bending and lateral loads at constrained locations at either end of the riser. The tapered design and its end connections are designed to meet an assumed maximum limit of metocean conditions and vessel movement that in turn dictates the window in which the MODU can safely operate.

A further constraint is the material that physically makes up the high pressure riser joints and how they're fabricated and connected. For higher loads and stresses imparted to the riser, higher strength materials must be employed. However, there are metallurgical and fabrication limits. High strength materials are uniquely susceptible to embrittlement and stress cracking when exposed to corrosive media such as hydrogen sulfide or salt water (chloride) infused fluids. Higher strength materials are more prone to premature failure under these conditions. Steel mill techniques that form pipe, have increasing manufacturing problems maintaining a uniform wall thickness and concentricity as wall thickness increases relative to pipe diameter (D/t ratio). If the thickness and ovality tolerances are too lax, the pipe may be prone to external pressure or buckling collapse; too tight and the manufacturing costs will make it too expensive and scarce.

Recommendation: Form an industry committee and/or study to address these issues and provide guidance for manufacturers, industry, and field inspectors to follow to help safeguard against failure.

Item #3: Dual Riser Pipe Configuration – Divide and Conquer?

A dual riser pipe design in a sense splits the loads acting on the overall system. The outer pipe is inherently larger in diameter and as such can withstand higher structural loads (σ = Mr/I), while limited to lower pressures (σ = PD/2t). That is acceptable in this instance because the smaller inner riser is shielded from the structural loads (outside) and is better equipped to deal with higher pressure loads inside. By splitting the loads, each pipe string deals with less combined stress, thereby making wall thickness and ovality issues less severe. In addition the environment is also split. To the outside, sea water is the corrosive agent acting on the outer pipe, while wellbore fluids are contained inside the inner string. It is not uncommon to have two different materials, with differing coatings, make-up connections and methods of construction customized for the specific riser pipe string. High pressure and high temperatures (HPHT) raises several interesting points. The inner riser may see much higher temperatures (in addition to pressure) relative to the outer riser, adding thermal growth into the mix of design issues.

Other challenges to a dual pipe drilling riser include: the added weight per foot of riser itself, the increased support requirements imposed on the riser tensioners, plus the added complexity to hardware design and operating procedures. These plus the added stiffness associated with locking two concentric pipes (greater moment of inertial (I)) make the riser much less compliant.

Therefore, it is recommended that the watch circle of the MODU be restricted so as not to overload the riser tensioner or the subsea wellhead from excessive loads. For these reasons, dual pipe drilling risers are better suited for TLPs and Spars.

Item #4: Large Bore Wells vs. Slimbore Wells

SBOP-high pressure drilling evolved from the notion of using a smaller casing approach to save time and consumables in drilling the well. Yet some of the larger TLPs and Spars have sufficient displacement capacity to support larger bore (more conventional) casing well programs. This allows standard casing hangers to be run and set while keeping the wellbore large for deeper drilling depths.

Item #5: Which Code to Use – Is there another way?

The SBOP drilling riser is often deemed “rigid high pressure piping”, and therefore subject to the design codes commonly used by the oil industry for piping design (ASME Pipeline Design Codes – B31.3, B31.4 and B31.8). But the pipeline design guidelines are based on quasi-static design conditions, not dynamic. Wall thicknesses are based on 67% and 83% of material yield strength for normal operating and test pressure conditions. API 16Q addresses marine drilling risers; but its design philosophy assumes short-duration exploratory drilling. Hence there are no provisions for fatigue limiting criteria or safety factors for extended drilling. Rather it focuses on extreme and survival conditions, resulting in a very conservative design.

API 2RD takes another step closer to the SBOP riser case and has become more prevalent design code in the Gulf of Mexico, partly because it has been written for the production risers, but more importantly that, “the design of risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) requires recognition that risers form a subsystem that is an integral part of the total system.” Its design methodology still uses the conservative approach of allowable stresses based on a percentage of yield strength. But API 2RD eases the design restrictions by employing multiple working stress design (WSD) limits for different load cases (normal operating – 67% of Ys, pressure test – 90% of Ys, and survival – 100% of Ys). This allows the allowable stress to be higher in low probability events, maintaining conservative calculations without driving to a single over the top condition. API 2RD is the most widely accepted steel riser code in the industry, and it is the required code for riser design in the Gulf of Mexico referred to by BOEM/BSEE.

There is another design philosophy whose acceptance is growing, especially in Europe - “Limit State” theory. Pipeline design codes DnV OS-F101 and API 1111 use Limit State theory for deepwater pipeline designs when ASME pipeline code values lead to pipe designs that no longer make sense from either an installation or on-bottom in-situ case. DnV OS-F201 has a similar design method for dynamic risers, and uses Limit State API 17G for designing completion/workover risers that access subsea wells.

There are numerous standards and guidelines for conventional drilling operations. Some of these cover many parts of the SBOP system design, configuration and operation. However, there are at present no SBOP specific guidelines that the industry can use in the planning and implementation of an SBOP operation. Consequently, the approach to SBOP operations within the industry has been driven by specific circumstances, individual operator requirements, and by IADC’s SBOP guidelines.

Recommendation: Industry should develop SBOP specific guidelines for use in planning and implemention of SBOP operation, taking into consideration the numerous standards and guidelines currently available for conventional drilling. These guidelines should offer examples for specific circumstances as well as provide exceptions for individual operator requirements.

<u>Item #6</u>: Standards that May Apply to Dual Bore Riser Designs

The session participants saw the advantages of limit state theory analysis and its advantages of addressing multiple load scenarios (pressure, tension, bending, cyclic bending-hydrostatic loading) that European codes and API 17G afford. Also noted were the improved performance benefits afforded by adopting the tighter tolerance of milled OCTG to API 17G rather than the API 5 series of codes. Other codes such as API 16Q were seen as being inappropriate for SBOP applications. The discussion soon boiled down to the realization that API 2RD is probably all that is needed, with a few simple suggested modifications. As mentioned, API 2RD employs multiple working stress design (WSD) limits for different load cases. For single string risers, this practice has served the industry well when designing and operating them in both drilling and production modes. However 2RD is silent on the dual riser string configuration. Therefore, it was recommended that an added section address the WSD for dual bore risers. (This recommended section is included in the full text of the white paper).

In summary, API 2RD and 17G are considered satisfactory for designing SBOP high pressure risers. Load Limit state and WSD design theory are seen as equally applicable. The WSD method in 2RD has proved adequate for the majority of Spars and TLPs up to now, and there doesn't appear to be any reason to stray from this current preference. However, there are a few suggestions for improving 2RD to make it more universally practical for production *and drilling* (especially dual bore) applications. API 17G focuses on single bore high pressure riser applications and is more practical for *workover* applications, but it is recommended for specification/qualification of other well control equipment.

<u>Item #7</u>: Various Other Questions (and Answers) Discussed in this Session:

A. What is the recommended number of rams; what type and in what order for the SBOP and SID? If a shear/blind ram is put on the SBOP, could a 'fish' drop and damage the SID barriers?
   - 3 to 4 rams on the SBOP as is conventionally done; blind, shear, casing (changing out sizes during drilling or using variable bore rams for drilling program). SID should have 1 or 2 blind/shear rams (keep its functionality to a minimum).
   - Dropping a fish on SID not an issue; close SID after a certain period of time; no changes to SID envisioned.

B. For design purposes, what pressure should be used within the ram wellbore? The current requirement is for the maximum anticipated surface pressure (MASP) – typically for a SBOP, but what should that be for the SID?
   - MASP, same pressure rating equipment for both SBOP and SID.

C. What is mechanism for regaining well control over a shut in SID with gas? With hydrocarbon liquid? (dealing with bottoms up effect) (Murphy Azurite considered a pipe ram in addition to a shear/blind ram (dual stack) as part of its lessons learned).

- Standard well control practice of circulating out a kick from anywhere in the well should be used. Riser and SBOP should be circulated bottoms-up with appropriate weight mud, and then open SID to release “bubble” and continue SBOP circulation well control operations. No need to modify or change SID with any extra equipment or lines.

D. Question: What is the most cost-efficient, yet safe control system for the SID? Electro-hydraulic multiplex? Acoustics, “Deadman” systems, ROV intervention, ROV hydrophone? If acoustics for SID control, how does one deal with the noise and shielding associated with a blowout plume?

Answer: Acoustic telemetry – electro hydraulic control with hydraulic accumulator bottles is one example.

<u>Recommendation</u>: Two backup systems should include ROV intervention primarily to recharge accumulator bottles, and battery powered “deadman” logic system should communication with the surface be lost. Consult with API Std. 53.

E. Questions: API 17H “high flow (HF)” receptacles with 1” bores have been specified for the subsea ROV interface. Hydraulic lines between these stabs and the function may be smaller and more restrictive. Is this the right standard? Should there be hydraulic isolation to the disabled control system to prevent back flow?

Answer: This is a possible addition to SID hardware, but simplicity is the operative word.
<u>Recommendation</u>: Consult with API Std. 53.

Answer: Some workshop participants feel there needs to be more than just a single hot stab for each function – an isolation feature and a hot stab function.

F. Questions: What types of MODUs are going to be allowed to use SBOP? Moored vs. DP vessels? TLPs/Spars only? What will be the allowed high pressure riser configuration for these (dual string, single string – SID)? Is there a water depth preference? Where should “Deadman”, auto-shear, and emergency disconnect functions be required for these configurations?

Answers: SBOP design is not recommended for MODUs unless designed to weather 100+ year storms. Okay for Spar and TLP. Single string or dual string design is okay provided there is an adequate HAZOP to identify and mitigate potential well containment issues. SID is only seen as another tool in Operator’s kit to choose from and use as part of well containment/control strategy – it’s not a mandated requirement. SID deployment may be a problem when well spacing or interior well access is required (as was mentioned about subsea BOP access).

Recommendation 1: SBOP design is not recommended for MODUs unless designed to weather 100+ year storms.

Recommendation 2: Initiate an industry committee or research effort to determine whether it is feasible to mandate use of SIDs. Representatives from the regulator should be included and/or kept apprised of the committee progress to offer guidance.

G. Are there different maintenance and protocols associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment?

- SBOP may use simpler land and platform based BOP operation and maintenance procedures and hardware. SID only has emergency close and open functions; far less than anything required for subsea BOP.

H. Are there different reliability and redundancy requirements associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment? How does one determine the efficacy level for maintenance of other SBOP/SID well control equipment?

- SBOP should follow established land/platform based protocols and studies should use established reliability/redundancy values for this equipment; same for maintenance, etc. This should be entirely separate and unrelated from subsea BOP protocols/reliability/redundancy values and practices.

I. Are personnel easier to train in operating, maintaining and use of well control equipment for SBOP-high pressure riser drilling than Subsea BOP and floating drilling operations?

- SBOP is seen as easier to grasp and teach than floating drilling/subsea BOP practices.

J. Question: Are personnel currently trained in operating the high pressure riser and monitoring its performance in the metocean environment?

Answer: A moot point if the vessel has 100 year storm survivability.

Recommendation: After a severe storm event, most equipment should be inspected for storm damage and visible or suspect equipment taken out of service for additional inspection or rework.

K. How does one inspect for premium threads and couplings during make-break and re-use? Are re-cuts required? Can they only be re-used once and only in a static condition (like SX)?

- Not addressed since make-breaks are seen as minimal (if ever) associated with Spars or TLPs. Standard thread inspection practices from Operator and manufacturer considered adequate.

L. Question: How does one determine the fatigue life for maintenance of high pressure riser?

   Recommendation: Follow practices in API 2RD or 17G.

M. How does one determine the fatigue life for maintenance of subsea wellhead? Are there any well foundation design or subsea wellhead rigid-lock requirements?

   - Follow practices in API 2RD.

N. Questions: Is IADC's *SBOP Design Guidelines* adequate for all other aspects of SBOP planning and operations? Should there be separate guidelines for shallow water vs. deepwater? Should there be separate guidelines for TLP/Spar vs. MODU?

   Answer: No need for specifics with respect to deepwater; deepwater practice should be the same as shallow water.

   Recommendation 1: SBOP/high pressure riser should be modified to include dual riser string configurations.

   Recommendation 2: MODU SBOP can be continued to be mentioned with the notation that it is not recommended for US unless MODU can shelter in place for a 100 year storm.

O. Should Standard 53 address SBOP-high pressure riser drilling? Does RP 96 properly address SBOP-high pressure riser drilling with respect to well design?

   - Not specifically addressed. Current codes appear to be adequate with respect to SBOP configurations.

P. Are there different well survivability issues (using the BOEM/BSEE well screening tool) that should be addressed in HAZOPs because of the SBOP-high pressure riser drilling?

   - No; screening tool is adequate.

Q. What should be done to address and minimize the effects of mechanical wear on adjacent production risers next to the drilling riser in the case of TLP/Spar well spacing?

   - Current riser pipe clashing analysis methods are well established and adequate for the job. Obviously well count, riser size and numbers, well spacing, water depth, metocean data, etc. will all play a role in design and analysis.

R. Question: What are the current mechanisms for aligning the Industry and the Regulatory Agencies?

Recommendation: Discourage use of SBOP for most MODU operations in US waters. Augment API 2RD for dual riser pipe applications. Use API 17G, 53 where practical.

S. Question: Gaps in regulations, standards, industry practices, collaboration and technologies.

Answer: Industry has good “managed pressure drilling” well control simulators; no additional work needed.

Answer: Well control computer simulators are not configured or available to address SBOP and SID; only SBOP only or subsea BOP only.

Answer: Capping stacks that are being developed for subsea BOPs may not be useful for SBOP applications.

Recommendation: Determine whether smaller stacks may be needed; a new configuration may be needed to deal with Spar/TLP deployment and for close well spacing applications.

Recommendation: Determine whether the IADC guideline should be “upgraded” to a Recommended Practice (RP) status to work toward a minimum acceptable level of reliability.

Technical Summary of Workshop Session #2 – Surface BOPs

This session of the workshop addressed over twenty five technical issues related to subsea blowout preventers (BOPs), and identified areas where two or more of the parties involved (BSEE, USCG, and Industry) can work together to seek clarification or agreement on actions needed to address specific regulations. The comments from the working sessions usually identified items that need to be clarified, or cases where industry and the regulator need to reach agreement on exactly what is being required in the regulation. The following is a list of issues or comments that were discussed in the session. More detailed text and discussion of these items may also be presented in the White Paper or in the body of the report.

Item #1:
Requirement for the submittal of documentation and schematics for all control systems (30 CFR 250.416(d)). This item addresses the submittal of sufficient current documentation and schematics for BOP control systems to allow intervention by another entity. Industry seeks clarification on the amount of detail needed in this type of submittal.
Recommendation: BSEE to collaborate with Industry. BSEE will identify the correct persons from BSEE to determine level of documentation required.

Item #2:
Requirement for a subsea BOP stack equipped with Remotely Operated Vehicle (ROV) intervention capability (at a minimum the ROV must be capable of closing one set of pipe rams, closing one set of blind-shear rams, and unlatching the Lower Marine Riser Package) (30 CFR 250.442(d)) (30 CFR 250.449(j)).
Recommendation: BSEE will review the proposed language in the new API Standard 53 for possible incorporation into the regulations. Industry has identified and proposed language in the new API Standard 53 for BSEE consideration into the regulations.

Item #3:
Requirements for independent third party verification that the blind-shear rams are capable of cutting any drill pipe in the hole under maximum anticipated surface pressure.
Recommendation: BSEE to respond to industry proposal. Wording proposal to BSEE: “Requirements for independent third party verification via theoretical, actual or historical reference - that at least one set of shear ram(s) be capable of cutting any drill pipe body, at maximum mud weight, or at the rated working pressure of the annular preventer - whichever is greater”.

Item #4:
Requirement for maintaining a ROV and having a trained ROV crew on each floating drilling rig on a continuous basis (30 CFR 250.442(e)).
Recommendation: BSEE to respond to industry proposal. Industry proposes that BSEE replace the word “continuous” in the current CFR with the words “when the BOP stack is deployed.”

Item #5:
Requirements for auto shear and 'deadman' systems for dynamically positioned rigs (30 CFR 250.442.F).
Recommendation: BSEE to consider industry proposal as set forth in API Standard 53. Industry understands the differences between the two emergency systems, agrees with these requirements and notes that API Standard 53 also includes moored MODUs.

Item #6:
Deals with the establishment of minimum requirements for personnel authorized to operate critical BOP equipment.
Recommendation: BSEE and USCG to agree on the intention of this requirement. BSEE may propose new regulations in the future to address this recommendation.

Item #7:
Addresses requirements for documentation of subsea BOP inspections and maintenance.
Recommendation: BSEE and USCG review and consider accepting proposed language in API Standard 53, "Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells." Industry indicates that the intended purpose of the statement is clear however, suggests that documentation for subsea BOP inspections and maintenance be according to Standard 53 (7.6.14.1) (7.6.14.2).

Item #8:
Deals with existing requirements for functional testing of all ROV intervention critical functions on subsea BOP stack during 'stump' test and function testing of at least one set of rams in initial seafloor test (30 CFR 250.449(j)).
Recommendation: BSEE and USCG to review and consider accepting proposed language in API Standard 53, "Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells." Industry to provide responses for clarification that result from review by BSEE and USCG.

Item #9:
Addresses the required function testing of auto shear and 'deadman' systems on the subsea BOP stack during the stump test and testing the deadman system during the initial test on the seafloor.
Recommendation: BSEE and USCG to review proposed wording from workshop, "Require function testing autoshear and deadman (ASDM) systems on the subsea BOP stack during the stump test and verify the deadman circuit operates as intended, following the BOP initial installation."

Item # 10:
After evaluating research on BOP stack sequencing and centralization, the Agency should consider including in the Safety Alert Recommendation to Lessees using a Subsea BOP Stack to centralize the drill pipe by means other than the annular preventer prior to activating the blind shear ram (BSR).
Recommendation: BSEE and USCG to consider wording as proposed at the workshop, "If the shear ram design requires the tubular to be guided to a predetermined position to effectively shear the pipe then provisions must be made to do so."

Item # 11:
Industry concurs with the requirement to conduct pressure testing if any shear rams are used in an emergency. The workshop Committee agrees with the current statement found in 30 CFR 250.451 (i). This includes inspection of the blades and pressure testing of the BOP's if any shear ram is activated and comes in contact with any component of the drill string. (Note: Only pressure testing of sealing type shear rams is required).

Item # 12:
The Committee agrees that the Agency should consider promulgating regulations that require operators/contractors to have the capability to monitor the SEM battery(s) from the drilling rig. The SEM battery, as described in this Report, is very important for the activation of the automatic mode function (AMF/deadman) system. If the battery is weak, the system may not function as it was designed. Having the capability to monitor the SEM battery status from the rig would help ensure sufficient battery power exists to execute the system.
Recommendation: BSEE and USCG to consider that not all ASDM systems use batteries and are therefore vendor-specific. Industry recommends the final requirement / rule wording include the following: "If the SEM design requires a battery, then provision shall be made to monitor the battery power."

Item # 13:
The Committee believes that the Agency should consider the design options on MODUs that could protect MUX lines during an explosion incident. As the Report to the President indicated, the initial explosions could have damaged or destroyed the MUX lines, thus rendering the rig BOP control system inoperable. Had the system remained intact and operable, personnel may have been able to activate any BOP function sequence.
Recommendation: BSEE to consider industry and USCG responses, "According to API Standard 53 (7.4.8.25), MUX cables are not required to meet fire test requirements of API 16D if the rig has auto-shear and dead man (ASDM) systems." The intention of having this "weak link" in place provides the means to automatically initiate the well securing process, in the event of the loss of power and communications to the subsea BOP. Prolonging that response could be detrimental to personnel and vessel safety. The USCG proposed a study of automated (or pre-emptive) systems to actively disconnect and shut-in the BOP to prevent an explosion. Industry is prepared to support USCG and BSEE in future studies and discussions.

Item #14:
The Agency should consider researching the standardization of Remote Operating Vehicle (ROV) intervention interfaces, ROV intervention capabilities, and maximum closing times when using an ROV.
Recommendation: BSEE to consider industry proposal of adopting API Standard 53, which suggests that the ROV system shall be equipped with '17H' single port hot stabs capable of closing the pipe ram and shear ram.

<u>Item # 15</u>:
The Agency should consider researching the effects of a flowing well on the ability of a subsea BOP to shear pipe. A clear definition of a flowing well is needed.
<u>Recommendation</u>: BSEE to consider collaborating with industry in defining the goals, objectives and scope for a study of this nature.

<u>Item # 16</u>:
The Agency should consider researching a blind shear ram design that incorporates an improved pipe-centering shear ram.
<u>Recommendation</u>: Industry to provide BSEE with the current status of several “non-proprietary” efforts that are currently being investigated. Several pipe centering designs are being considered at this time (1. NOV – Centering, 2. GE – Centering, 3. Enovate – centering not required). Please see Item #10 above for possible language for rulemaking requirements.

Other Findings and issues related to subsea BOPs:

a. USCG is interfacing with subsea marine groups to make a draft document for testing and inspection. Schedule for draft: December 2011.

b. Industry is seeking information about mandates on Emergency disconnect systems – BSEE is working on three high priority items. Industry is seeking more of a wide-open forum to provide industry feedback. Schedule: Early 2012.

c. Industry prefers technical bulletins for battery voltage monitoring over regulations. BSEE thinks the regulation should apply “to the situation”. BSEE tries to ensure that industry has the correct understanding of the regulation.

d. Industry’s question: How do you challenge a finding/citation? BSEE: There is a formal procedure in place to provide explanation. The regulatory agencies are open for discussion.

e. BSEE is working to achieve more consistent formal training for inspectors. As stated during the opening remarks of the workshop, BSEE has also initiated action to develop an internal National Offshore Training and Learning Center to further educate and train BSEE staff engineers and inspectors.

General Issues Arising from Breakout Session on Subsea Blowout Preventers

This part of the Session is striving to identify actions that can improve offshore operations and regulatory oversight. In order to facilitate this, BSEE has suggested the following:

- Brainstorming to identify topic issues and technology challenges, including areas where further guidance is needed (e.g., industry standards and regulations);
- Identify, discuss, and agree on recommendations;
- Identify the Significance (Priority Level) of the issue and/or recommendation; and
- Identfy the responsible party for addressing the issue and/or recommendation.

The following items represent a list of future collaborative issues.

Issue A: Industry: Compliance versus redundancy is an industry concern.
Recommendation: Possible improvement of the risk assessment process with specifics in clarity on “critical vs. non-critical and primary vs. secondary and redundancy.”
Priority: High
Responsible Party: BSEE in collaboration with the industry.

Issue B: Regulator: Is there room for a fully automatic (drilling) system?
Industry: While marine propulsion system is self-communicating, the well itself needs human interaction.
Recommendation: Consider actions in other industries, w.r.t alarm management, early detection and roles and responsibilities and training.
Priority: High
Responsible Party: Industry

Issue C: Industry: Kick detection/early warning systems on floating platforms. (Flow measurement is an issue).
Recommendation: R&D of wellbore fluid management systems.
Priority: High
Responsible Party: Industry

Issue D: Industry: Recurring problems with the same components, lack of knowledge transfer among component manufacturers, contractors, operators.
Recommendation: Cross-fleet, good operating practices, improve and open the lines of communication among all parties.
Priority: Low
Responsible Party: Industry

Issue E: BOP maintenance – no mechanism for ensuring for adequate crew competency. Well control has certifications but BOP maintenance crews do not.
Recommendation: Establish Standard for ensuring BOP maintenance competency
Priority: High
Responsible Party: IADC Committees in collaboration with Industry.

Issue F: Industry: Seeking clarifications on existing BOP stack requirements: shearability; well control; and configuration.
Recommendation: Consider ISO 13628-7 as a guiding document.
Priority: High
Responsible Party: BSEE in collaboration with the industry.

Issue G: Industry: Concerned that frequent testing can reduce the reliability of components.
Recommendation: Real-time monitoring of performance, Risk based testing frequencies. Is SILS rating an option?
Priority: High
Responsible Party: Industry in collaboration with BSEE on acceptability.

Issue H: Regulator: USCG asked, “Who should control the well in case of a kick? How to pinpoint a major issue from a number of minor issues that happen together? Industry responded: *Wellcap* is one of two industry standards used in certifying personnel in well control.
Recommendation: Better communication among the various industry initiatives that are working on this issue.
Priority: High
Responsible Party: Industry

Technical Summary of Workshop Session #3 –
Well Drilling and Completion Design and Barriers

The final version of the white paper for this session (see Session 3, White Paper) has been updated based on the discussions held at the workshop. The white paper provides background on the topic and identifies current trends and challenges in this area. The following technical summary is based on the information presented in the white paper and at the close-out reporting session of the workshop. More background and detailed information on the topics, observations and discussions below may be found in the white paper and in the final session #3 close-out report (see Session 3, Close-out Report).

The white paper for Session 3 addresses:

- Current technologies and challenges associated with implementing these technologies
- Trends and/or notable technologies envisioned for the near and long-term
- Coordination and communication to help align the efforts of Industry and regulatory agencies
- Human factors in safety (e.g. training, procedures)

Regarding current technologies, the white paper addresses three questions associated with implementing these technologies:

1. What Challenges Exist in Casing and Equipment Design for Deepwater Wells?
2. What are the Operational Challenges with Implementing Reliable Barrier Systems?
3. What Challenges Exist in Deepwater Completion Designs?

The following technical summary highlights the important issues and workshop discussions held during Session 3. The purpose of the workshop was to identify the issues and challenges of deepwater drilling and well control and identify recommendations for improvement. Although reaching consensus was desired, the complexity of technologies, operations and objectives of the 30+ Subject Matter Experts (SMEs) present, produced diverse positions. Where consensus could not be reached, this summary attempts to capture the varied positions of those discussions, laying the groundwork and leaving the door open for future discussions.

Note: To simplify this summary, general terminology such as “Industry”, ‘Operator” “BSEE”, “regulator”, etc. has been used to identify the parties. It should be noted that use of the term “Industry”, for example, does not imply that all of Industry shares that position or understanding. The same applies for “Operator”, “BSEE”, and the other general terms used.

Observations and Discussion Items from Session 3:

1. Well Design Implications for Containment – The workshop provided an excellent opportunity to discuss well design implications under the new containment plan requirements. Under the new regulations, the BSEE requires operators to have a containment plan that will accommodate a well that has been fully evacuated to an unconstrained flow of reservoir hydrocarbons. It became clear during the development of this summary document that Industry and regulators continue to have differing understandings regarding the implications of this requirement on well design. The following is intended to summarize the understandings of both Industry and regulators at this time. Continued discussion is welcomed.

   Industry is of the understanding that they are currently required by the BSEE to design wells and systems that will contain reservoir fluids following a sustained worst case discharge (WCD) blowout. BSEE's response is that the requirement is not focused on well design but rather on the ability of the operator to contain the full evacuation of reservoir fluids.

   Editor's note: There remains a fundamental difference of understanding between BSEE and the Industry concerning the definition and implications of WCD. A focused discussion on this topic would be helpful in clarifying the issues.

   While well design is not specifically addressed in Notice to Lessees (NTL) No. 2010-N10, “Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill response and Well Containment Resources,” Industry interprets the regulators to mean that all deepwater well designs must ultimately be adequate to contain an uncontrolled flow from the reservoir that is expected to be encountered by that wellbore. Industry understands that containment may be accomplished either by the well design alone or by considering the well design within a larger containment system. The Well Containment Screening Tool, developed by a Joint Industry Task Force, is used to determine if a wellbore design is adequate for containment by either the “Capped” or “Cap and Flow” methods.

   Industry believes that well Design Load Cases have changed with the new containment requirement (see Addendum to White Paper #3). However, BSEE stated during the workshop that the containment plan is catered to the well design and reservoir potential and the NTL is not meant to mandate well design changes.

   Industry interprets that containment requires that the wellbore must be designed such that it will survive a catastrophic blowout event with sufficient integrity to be either “Capped” or “Capped and Flowed” to stop hydrocarbons from entering the marine environment. A “Capped” well must be able to sustain the pressure resulting from shut-in of a full column of reservoir fluids from the wellhead to the reservoir. Underground flow may be allowed as long as reservoir fluids do not broach to the seafloor (note: the BSEE indicates that substantial subsurface geological and geophysical analysis would have to be accepted to allow for this). BSEE's position is that the Containment Plan must address any failures identified in the screening tool by demonstrating the ability to contain the well without fluids broaching the seafloor. A well can be designed for "Cap and Flow" if adequate surface and subsea containment system capacity exists to support the potential flow from the reservoir. In the "Cap and Flow" case, the well would be produced to the surface containment system. As a flowing well, a "Cap and Flow" well design would not require the well to survive full shut-in pressure.

Some within Industry feel that containment requirements change the design load requirements for intermediate casings. The containing casing must be designed for the collapse load of an unconstrained flowing hydrocarbon column and for the burst load of either full or partial shut-in. In addition, the well must withstand annular pressure build-up (APB) associated with the sustained flow of reservoir temperature fluids. The workshop identified disparities between some within Industry and BSEE, where BSEE emphasized that design changes are not required but that any potential failures are considered in the design of the containment plan.

Some within Industry feel that this requirement has potential to significantly impact design, affecting not only the casing design (setting depth, weight and grade of the casing), but also the mitigations required to counter APB. This approach addresses the low-probability risk of a WCD blowout but adds higher-probability operational risks, creates inefficiencies, and limits operational capability. BSEE recognizes the potential for redesign under some instances including cases where the operator chooses to have a more robust design, however, BSEE points out that operators can design wells as they always have. The containment plan must demonstrate the ability to handle a blowout event (full evacuation to reservoir fluid). If it is determined the containment capabilities are not possible, only then would the wells design have to be reworked.

Operators want to retain the option to design casing programs using load criteria that was acceptable to regulators pre-Macondo. BSEE's position is that they have that option. Operators would prefer to address the process safety risk of a blowout with process safety solutions, such as BSEE's Safety and Environmental Management Systems (SEMS). The preferred approach by Industry is the proactive avoidance of this worst case rather than a regulated structural safety solution that might be required following the most extreme blowout event. Some within Industry feel that, per NTL 2010 N06 FAQ's, all well designs are now to be capable of surviving a WCD blowout without any internal restrictions and with no Blow-out Preventer (BOP) on the well. BSEE states that N06 does not influence well design. Instead, N06 says that the WCD cannot consider restrictions in the wellbore. According to BSEE, N06 addresses the WCD volume for spill response planning and the operator must demonstrate that they have planned and are prepared to contain the highest discharging well in their asset of wells in the GOM.

Operators believe that this design criterion and its associated load cases are now required for all deepwater wells in the Gulf of Mexico (GoM), regardless of procedural mitigations that may be in place to reduce the risk of occurrence. Operators request that regulators consider alternative design criteria on a well-by-well basis. These design criteria would be established with consideration for the newly regulated SEMS process safety solutions. BSEE's position remains that operators can design wells as they always have, provided that they demonstrate the ability to contain a blowout.

Editor's note: There remains a fundamental difference of understanding between BSEE and the Industry concerning the definition and implications of WCD. A focused discussion on this topic would be helpful in clarifying the issues.

2. Annular Pressure Build-up (APB) Mitigation - Well designers want to retain the ability to choose APB mitigations that address credible risks during well construction and operation. Because of the extremely low probability associated with the WCD load case, Industry recommends that WCD not be used to dictate APB mitigations. BSEE states that WCD, or more precisely, wellbore evacuation to reservoir fluid is not used to dictate APB mitigations. Wellbore evacuation to reservoir fluid is used to assess the well's design in order to know how the containment plan is to be designed.

   Editor's note: There remains a fundamental difference of understanding between BSEE and the Industry concerning the definition and implications of WCD. A focused discussion on this topic would be helpful in clarifying the issues.

3. Regulator Interpretation of the American Petroleum Institute's (API) use of "Should" and "Shall" - From the March 28th, 2011 document issued by BSEE entitled "Supplemental Information Regarding Approval Requirements for Activities that Involve the Use of a Subsea BOP or a Surface BOP on a Floating Facility," item 1 (b), it is understood that the BSEE is reconsidering their interpretation of API's definitions of the use of "should" and "shall" in those API documents that have been incorporated by reference into the federal Code of Regulations (CFR), reference 30 CFR.250.198 (a) (3). It is requested that any new interpretation be officially published in the CFR for use by Industry. BSEE will address this in the Final Safety Measures Rule, to be published in the Federal Register and the final regulatory language will be incorporated into BSEE regulations.

4. Clarification on Maximum Allowable Surface Pressure (MASP) Calculation – Industry feels there are multiple references to MASP but little guidance as to what is the minimum acceptable method to be used to calculate same. The wellbore containment screening tool does have some guidance regarding different gas gradient assumptions based on well depth that may be used to determine containment capability, but nothing is stated in the CFR or elsewhere in regulations. Before the Macondo incident there were many variations of the calculation in use. A clarification of the allowable methods for the calculation of MASP is requested by Industry. BSEE response is that they do not prescribe how to calculate MASP.

BSEE may provide how they calculate MASP but that approach is not required. If an operator's method exceeds BSEE's values, it is acceptable. If the Operator's method's results are less than BSEE's results, it is not acceptable unless the operator can provide sufficient PVT data to support their results. Otherwise, they are held to BSEE's calculated values as a minimum.

5. Reliability of Mechanical Barriers - The reliability of a mechanical barrier can be established by various factors including quality in design, manufacture, installation, and testing.

6. Reliability of Cement Barriers - The reliability of an annular cement barrier is strongly influenced by the effective removal of the drilling fluid from the desired zone of cement coverage, water wetting of the casing and formation, and the placement of competent cement to form a hydraulic seal around the entire cross section of the annulus. The ability to achieve a reliable annular barrier involves balancing the competing priorities of annular clearance and casing centralization. These physical attributes, clearance and centralization, are particularly important in close tolerance casing programs.

7. Mechanical Lock-Down of Hanger and Hanger Seal Assemblies - The requirement to lock down seal assemblies should apply only to those seals with the potential for exposure to hydrocarbons.

8. In-situ Verification of Barrier Integrity - Regulations should change to require only one pressure test of a dual barrier system. Additional work should be undertaken to establish standards that improve the reliability of "negative" pressure tests.

9. Casing and Cementing Equipment Reliability - There is a need to identify and reduce common equipment failure modes; to increase the reliability of individual casing/cementing equipment components; and to improve the integration of these components into highly reliable barrier systems.

10. Long String versus Liner and Tieback – Industry feels that a long string is a viable alternative to liner and tieback designs. The long string provides advantages in many deepwater well applications. Both designs have merit and should continue to be available to well designers. BSEE's position is that both designs remain available.

11. Production Liner – Well Control Design Options - For well control scenarios, it is important to retain the design option to allow for production liner collapse. Liner collapse can be an effective way to mitigate flow from the reservoir under extreme well control conditions.

12. Working Pressure Ratings of Subsea BOP Equipment - The prediction of the benefit derived from hydrostatic pressure back-up is straightforward for simple geometries such as tubulars. The benefit to more complex geometries, such as subsea BOP equipment, is not as easily predicted. Industry should continue to work to estimate

the working pressure benefit that can reliably be provided to subsea BOP systems as a result of environmental pressure effects.

13. Stimulation of Deep Tight Formations - The commercial development of deep tight formations will require special production stimulation techniques that may exceed current capabilities.

14. Well Intervention Systems - Intervention operations on deeper and higher-pressure wells may exceed the capacity of available equipment. Additional development of intervention systems will be required.

15. Low Cost Reservoir Access - While low cost reservoir access techniques have been successfully used in recent years, the development of specialized equipment, systems and deployment vessels will be required to make full use of this approach to access deepwater Gulf of Mexico reserves.

Findings:

Issue #1:
The Session participants agreed that the workshop was worthwhile. The discussions provided useful information for both Industry and the regulators present. Industry has made considerable progress over the past year with new API Joint Industry Task Force (JITF) Reports, the development of new standards, and the delivery of the well containment systems.

Recommendation: More workshops – Subsequent workshops should be broken down into sub-categories so that more effort can be focused on specific topics and issues. Possible areas for discussion, of interest to this working group, include:

1. Risk assessment on rules that add additional risk to the drilling and completions process – with a focus on total system reliability.
2. Further clarification on NTL 6 and NTL 10 and their impact on casing design.
3. Further discussion on barriers. (API RP 96 needs to be issued and placed into use. There will be a need for additional technical discussion once this document is implemented.)

Priority: High

Responsible Parties: Regulators, Industry

Issue #2:
Well Containment Screening Tool Usage (Clarification of Requirements Affecting Casing Design). NTL N10 – Containment system must be designed and available to handle a WCD (using one of three options):

- L1 - BOP Shut-in or Capping Stack (simplified assumptions). Industry asserts that High Collapse Casing is required in some cases. BSEE position is that they do not require high collapse casing to be installed; this is something the operator could choose to do.

- L2 - BOP Shut-in or Capping Stack (advanced analysis). Underground Flow or Collapse may be allowed provided that hydrocarbons do not broach to the seafloor. Further analysis needed to evaluate different gradients, different burst rating, and confirmation of no annular pressure build-up. BSEE agrees, however, additional subsurface geological and geophysical analysis must be provided to allow for this scenario.
- L3 - Cap and Flow - Flowing Pressure Managed at Seafloor (a permit has been issued for this approach). BSEE expected to routinely authorize this approach. Collapse, which may reduce burst loads, can occur, provided that hydrocarbon flow is contained and collected.

Editor's note: There remains a fundamental difference of understanding between BSEE and the Industry concerning the definition and implications of WCD. A focused discussion on this topic would be helpful in clarifying the issues.

<u>Recommendation:</u> More meetings and discussions, as mentioned in Issue #1 above.

<u>Priority</u>: High

<u>Responsible Parties</u>: Regulators, Industry

<u>Issue #3:</u>
Blow-Out Load Case Evaluations (Clarification of Requirements affecting Casing Design)

a. WCD is defined by NTL N06. According to BSEE, N06 addresses the worst potential discharge that may occur on the operators lease block and has to be responded to per the spill response plan for clean-up and environmental mitigation. N10 addresses the full reservoir evacuation for the individual well that has to be contained.
b. Industry's interpretation is that NTL N10 is being used to define Casing Design Requirements that ensure that sufficient wellbore integrity remains after a WCD incident to contain the wellbore fluids (containment may be either accomplished below the seafloor or by flowing back to surface containment equipment). According to BSEE, the containment plan is catered to the well design and reservoir potential and the ability of the operator to contain the full evacuation to reservoir fluid. The NTL's intent is not to institute well design changes.
c. Casing Collapse Allowed by BSEE – Casing that will collapse under blow-out load is acceptable (as long as reservoir fluids do not broach to seafloor). BSEE will not allow reduced blow-out rates based on predicted casing collapse (still need full flow containment capability).
d. Operators view this as a new requirement; addressing a low-probability event, that creates issues with operational safety, efficiency and capability. Operators would like the ability to demonstrate how process safety can be used to address these

issues, instead of this regulated structural safety approach. BSEE's position is that well design changes are not being required, only that well containment be demonstrated. If containment cannot be demonstrated, changes are at the operator's discretion and, as such, the operator is responsible for risks added due to those design changes.

Editor's note: There remains a fundamental difference of understanding between BSEE and the Industry concerning the definition and implications of WCD. A focused discussion on this topic would be helpful in clarifying the issues.

Recommendation: More meetings and discussions, as mentioned above.

Priority: High

Responsible Parties: Regulators, Industry

Issue #4:
Review of policy regarding API documents incorporated by reference into the CFR.

Recommendation: Review departure requests to identify cases where a change in regulations may be appropriate. Consider a Final Rule to clarify "shoulds" and "shalls." BSEE will publish a Final Rule that will address the comments received on this issue.

Priority: High

Responsible Parties: BSEE

Issue #5:
Coordination & Communication to align Industry and Regulators - need to exploit available alignment mechanisms (e.g., meetings like this Workshop and advance notice of proposed regulation). Since Macondo, NTLs have been issued to reduce the time required to have regulations in place. The standard rule-making process can be lengthy. Industry would like to be able to comment on NTLs. An Advance Notice of Proposed Rulemaking (ANPR) does not replace a rule; it is an optional step in the rulemaking process that is published before actual regulatory text is developed, to allow early input in the rulemaking process. An ANPR can be a useful tool, to communicate to the public what regulations are under development and receive early input; however, it does make the rulemaking process longer.

Recommendation: Consider a mechanism for Industry and any interested parties to comment on NTLs before they are issued. BSEE's position is that while sharing draft NTLs is not prohibited, a Federal Register notice would be the best way to ensure fairness in requesting comments from any interested party on NTLs, to and promote transparency BSEE may make the comments received on a draft NTL publicly available. This would lengthen the NTL development process. If BSEE were to seek comments on NTLs only from certain groups could trigger certain legal issues.

Priority: High

Responsible Parties: Regulators, Industry

Issue #6

Various Issues of significance, and potential importance were not fully addressed in Workshop session due to time constraints, including:

1. Fracture Modeling in Salt;
2. Further understanding of connection performance in collapse scenarios;
3. Safer Wells through an improved understanding of the physics of Barriers (strength and resistance);
4. Review of the API RP96 discussion of Barriers (Operational Barriers, Shoe Tracks);
5. Pursuing potentially interesting technology for monitoring pressure and temperature below barriers and in trapped annuli;
6. Current development of APB solution alternatives (shrinking fluid, memory foam).

Recommendation: Regulators and Industry should continue to work together to build consensus on these issues.

Priority: Medium

Responsible Parties: Industry, Regulators

Technical Summary of Workshop Session #4 – Pre-Incident Planning, Preparedness, and Response

This session of the workshop addressed several technical issues related to Pre-Incident Planning, Preparedness, and Response, and identified areas where two or more of the parties involved (BSEE, USCG, Industry and other stakeholders) need to work together to seek clarification or agreement on actions needed to address specific regulations. The comments from the working sessions identified items that need to be clarified, or cases where industry and the regulator need to reach agreement on exactly what is being called for in the regulation. The following is a list of issues or comments that were discussed in the session.

General Description, Comments, and Observations:

<u>Item #1:</u> Phases of Emergency Response:
<u>Discussion:</u> The Three Phases

- Immediate Response – The first 48 hours post incident – mainly rig based or area close to the rig.
- Intermediate Response – After the first 48 hours post incident, including rig based and beyond. The intermediate time-frame ends when debris removal begins, the capping stack arrives, or when the flowback system arrives on site.
- Long Term – All remaining activities.
- The Hierarchy of Priorities for all decision making is: Human Life and Health, the Environment, and then Physical Assets.

<u>Item #2:</u> Subsea Dispersants:

<u>Discussion:</u>

- The USCG has the authority to grant the use of dispersants subsea to protect the health and safety of responders during the initial response (Industry has a JIP on dispersants going on now).
- Shallow Water Dispersant Challenges: deepwater dispersant mixing is good, but the performance in shallow water is unknown.
- It is more difficult getting approvals for dispersant use in shallow water, i.e. closer to shore. There is not a pre-authorized monitoring plan for dispersant use which can be prepared for in advance.

<u>Recommendations</u>:

- Federal Agencies & Industry should address all of the challenges related to subsea dispersant application. A clearly documented approval process is needed. A pre-approved monitoring plan / conditions of use for dispersants would be helpful.
- Consider Inviting EPA to any future Oil Spill Workshops.

- Perform Norwegian style oil-on-water response and clean-up exercises here in the US and led by the US Government. This would require considerable internal discussion between the offshore regulators (BSEE, USCG, EPA, NOAA, FWS, etc.) well in advance to reach agreement and develop guidelines for this controversial practice.

Responsible parties: Federal Regulators, Industry and other stakeholders.

Item #3: Burning of Hydrocarbons:

Discussion:

- Sometimes burning of hydrocarbons is a good choice, e.g. if a flare boom is available, or if wind, weather and other conditions are favorable. However, there is no clear path for prior approval. It is clear that all government bodies, the EPA and the Federal On-Scene Coordinator (FOC) need to be involved with such a decision.

Recommendation:

- Industry suggests working with BSEE, USCG, and EPA to develop criteria that can be established in advance, and implemented at the time of an event with FOC approval. EPA needs to be involved in advance to identify a clearly defined monitoring program.

Responsible parties: BSEE, USCG, Industry and other stakeholders.

Item #4: Incident Command Structure (ICS)

Discussion:

- National Contingency Plan is preferred for Oil Spills whereas the Stafford Act applies to natural disasters. We should follow Homeland Security Presidential Directive #5 – which clarifies government roles and jurisdiction. The USCG is the federal on-scene coordinator for offshore spills, and USCG uses BSEE as the subject matter experts (SME) on well issues. Need to have all incident-related participants following ICS.

Recommendations:

- All parties (Federal, State, Local, Industry, etc.) follow the National Contingency Plan & Incident Command Structure (ICS).
- Update & Improve the Area Contingency Plans for consistency and integration with Oil Spill Response Plans (OSRPs).
- Suggest coordination of all efforts to improve incident prevention and response Training.

- Continue to meet on a regular basis and maintain a high level of communication and coordination among all parties involved with Incident Planning, Preparedness, and Response.

Responsible parties: BSEE, USCG, Industry and all related stakeholders.

Item #5: ICS Communications

Discussion:

- Communications plan for the Response team must be well thought out and comprehensive.
- It is expected that the response plan will make provisions for video feeds from the Remote Operating Vessel (ROV) and possibly other video feeds.
- Strong need for a plan to coordinate marine radio & aviation radio frequencies.
- Because of the greater distances involved, deep water will need more communications capacity than shallow water operations.
- The Incident Command Structure (ICS) model during a recent event worked well with:
  - Marine Vessel Traffic coordination
  - Air Traffic / Airspace coordination
  - Subsea ROV coordination

Recommendation:

- Industry and regulators (BSEE and USCG) should hold a workshop to determine the need for and/or develop recommendations to address the first four bulleted items above.

Responsible parties: BSEE, USCG, and Industry.

Item #6: Training

Discussion:

- Are current training programs adequate? It appears that improvements to “situation training” are needed in the area of well control. This would effectively “raise the bar” on well control training.
- Several groups working on this topic: IADC, OGP, Norway

Recommendation:

- It might be beneficial to have a workshop on this topic, and look at what other groups, e.g. nuclear, aerospace, chemical, are doing.

Responsible parties: Industry.

Item #7: Preparation for Emergencies

Discussion:
- Alignment within the industry is a must, especially with regard to Drills and Exercises.
- Perhaps we should consider larger exercises on a less frequent basis.

Recommendation:
- Further Discussion Needed on Jurisdiction – possible Jones Act issues.
- For larger drills, the proper government agencies need to be involved and to participate.

Responsible parties: Industry and Regulators (BSEE & USCG).

Technical Summary of Workshop Session #5 –
Post Incident Containment and Well Control

This session of the workshop addressed several technical issues related to Post Incident Containment and Well Control and identified improvements that have been made since the time of the Macondo incident. It also identified areas where two or more of the parties involved (BSEE, USCG, Industry and other stakeholders) need to work together to seek clarification or agreement on specific regulations.
The following is a list of issues or comments that were discussed in the session.

Technology

Item #1: Scope

Discussion:
Session #5 is about the design, implementation, and deployment of deepwater subsea containment systems. These systems would be deployed on “blowout” wells that are being drilled or completed from floating vessels or a floating production structure (such as spars or tension leg platforms (TLPs)), including wells utilizing subsea wellhead/Blowout Preventer (BOP) systems and those wells utilizing surface wellheads/BOPs . The subsea containment systems would, in all cases, be deployed on the seafloor. The systems would be used to achieve one or more of the following:

- Full shut-in and containment of the well via well capping.
- Shut-in of the well with subsurface pressure relief that will not broach the seafloor.
- Containment of the well within a system that allows flow to the surface until a relief well can be drilled.
- Provide for well kill operations such as top kill, bull heading, volumetric kill, and/or secondary intervention by another vessel or rig.

Item #2: MWCC

Discussion:
The Marine Well Containment System and Marine Well Containment Company (MWCC) have been established to enhance industry subsea containment capabilities. The MWCC is a not-for-profit; independent organization committed to being continuously ready to respond to a well control incident in the Gulf, and is committed to advancing its capabilities to keep pace with its members’ needs. Membership is open to all companies operating in the U.S. Gulf of Mexico.
Item #3: HWCG

Discussion:
Twenty-four deepwater energy companies have joined to form the Helix Well Containment Group (HWCG) to develop a comprehensive and rapid deepwater

containment response system. The HWCG has invested in technology & engineering and applied lessons learned from the past, to create a comprehensive well-containment response system made up of equipment, procedures and processes ready to be activated immediately in the event of a subsea well blowout. The HWCG is organized under Clean Gulf Associates, who provides administrative and member services.

Item #4: Subsea Containment Response Sequence

Discussion:
After a blowout the response sequence for subsea containment is the same for all existing and near term technology. The sequence is:

1. Attempt to intervene and gain well control via the BOP stack using ROV intervention. Gather data with ROVs and other devices and instrumentation.

2. Deploy debris field clean-up resources if there is debris and begin removal. This would include multiple ROV manipulated cutting & handling devices along with ROV hydraulic power units for large scale work.

3. Immediately deploy the capping stack, subsea dispersant injection system, methanol injection, and open water capture device. Begin subsea dispersant injection and capture with the open water device.

4. Install the capping stack. Provide hydrate mitigation as required. Several different means exist for transporting and handling the capping stack. These can be limited by the size and weight of the capping stack.

5. Shut the capping stack & shut-in and fully contain the well. If there is minimal debris and there is a clean connect point where the LMRP has released, this is a straight forward operation to install the capping stack. The well is then fully contained and the event is fully controlled. No other containment equipment is required. Achieving this operation successfully is the prime goal of all containment work.

6. If the capping stack alone does not achieve the desired shut-in and containment, deploy the flow system. The flow system involves the manifolds, risers, interconnecting piping, control systems, and surface facilities to flow hydrocarbons to the surface from the capping stack. On the surface the hydrocarbons are captured and the gas is flared and the oil and water are transported to shore by shuttle tankers.

Item #5: Effects of Water Depth on Containment Capability

Discussion:
The effect of water depth on containment is minimal. The full MWCC expanded system will be capable of working in 10,000 feet of water. The maximum depth in the GOM is between 12,000 and 14,000 feet. Current exploration and production is not occurring in more than 10,000 feet of water. Thus containment systems do not have a water depth limitation or technical limitation related to water depth in the GOM. Current flow systems are not recommended for use in water depths less than 500 feet.

Operations/Standards

Item #6: Incident Command Structure

Discussion:
Current incident command mechanisms did not anticipate subsea containment events and their technical complexity.

Recommendation:
Consider developing improving organizational structures, definition of responsibilities, and incident command functioning for a major subsea containment event. This improved ‘command structure/ infrastructure’ should include government & industry with pre-defined roles & responsibilities and include enhanced cooperation/collaboration.

Priority: High

Responsible Parties: USCG, BSEE, the E&P industry, and other stakeholders.

Item #7: Clear and Consistent Definition of Containment and Containment Standards

Discussion:
There is currently no regulatory guidance or API or ISO standard for BOP capping stacks. There is no ‘recommended practice’ or API RP on well containment measures, techniques, and planning. However, task groups have been commissioned to create both documents.

Recommendations:
- API should complete and issue new/updated API documents: RP 96, Std 53, and Bul 97 (both of these efforts are in process at this time).
- Develop a mechanism to ensure that the growing guidance in support of NTL No. 2010-N10 is based on a collaborative dialogue that ensures that recommendations and decisions are focused on determining and addressing those areas that focus on the significant hazards and deliver best results in hazard mitigation.

Priority: High

Responsible Parties: USCG, BSEE, EPA, State governments, the E&P industry, and other stakeholders.

Item #8: Simultaneous Operations (SIMOPS) – a major challenge

Discussion:
A subsea containment response requires many vessels in various sizes including shuttle tankers, aircraft, and numerous ROVs. It is a significant challenge to manage all this equipment and its operation. This is further complicated by the small operating area and the risk of collision. There is also the fact that all the SIMOPS have to be done with all equipment in close proximity to volatile hydrocarbons.

Recommendations:
Continued meetings and exercises are essential to developing the kinds of communications and cooperation needed to avoid the risks of collision and damage to the recovery equipment itself. The use of chemicals for managing volatile hydrocarbons should be addressed.

Priority: Moderate

Responsible Parties: USCG, BSEE, EPA, Industry, and other stakeholders.

Regulations

Item #9: Use of Dispersants

Discussion:
Industry needs clear and concise regulatory guidance on the use of dispersants during incident response. Dispersants ameliorate volatile organic compounds during incident response. The Macondo response clearly showed that the use of dispersants enhanced the ability of vessels and crews to operate at the site and respond to the incident.

Recommendations:
- Industry should improve the efficiency and effectiveness of dispersants during a response. This work should consider use rates, dispersants specifically formulated for subsea use and enhanced mixing and injection techniques including mechanical devices.
- The regulatory environment needs to initiate internal communications toward support of the use of dispersants in subsea containment responses. What, if any, monitoring is involved with the use of dispersants?

Priority: High

Responsible Parties: USCG, BSEE, EPA, Industry, and other stakeholders.

Communications

Item #10: Industry and Government Agency Communication and Cooperation

Discussion:
There are opportunities for improvement. Perhaps most important is the enhanced clarity and certainty that comes from including industry input and comments into the regulatory process. A companion to this is more and better dialogue and understanding between industry and regulators in general. A good way to create more dialogue is to have increased regulatory participation from BSEE, USCG, and EPA in the development and review of industry standards. This occurred more in the past but seems to have reduced significantly in the last few years. The recently established containment companies and mutual aid resources regarding emergency response are an entirely new and unprecedented forum for cooperation and collaboration. They also have active dialogues with the regulators.

There also needs to be a functioning Center for Offshore Safety (COS) to share safety management system best practices while removing barriers to sharing of industry issues regarding safety.

The newly established Federal Advisory Committee (Ocean Energy Safety Advisory Committee) brings together all segments of the industry including the regulators and government to work cooperatively to develop solutions to these challenges. Industry Conferences, Forums and Workshops as well as Industry Trade Associations have always played a key role in helping to stimulate collaboration. Industry events are opportunities for open communication. Two other organizations help to enhance coordination and communication:

The Offshore Operators Committee (OOC) is the recommended organizational point of contact to provide an ongoing interface between offshore operating companies, suppliers and regulators. It would be beneficial to further develop this relationship to address cultural issues in support of enhanced offshore safety.

The Petroleum Equipment Suppliers Association (PESA) is the recommended organizational point of contact to provide an ongoing interface between suppliers of offshore oilfield equipment and services and regulators.

Item #11: Other Containment-Related Topics that Could Benefit from Discussions at a Workshop

Technology

- Dispersants

    - API Oil Spill Preparedness & Response Subcommittee
    - Mixing Equipment of Dispersants (especially Shallow Water)
    - Industry Survey of Methanol & Dispersant Transport & Storage Capacity
- Well integrity determination (B annulus pressure monitoring)
- In well shut-in devices & supplemental shearing
- MWD Ranging Tools
- High Resolution Seismic
- Survey of ultra-deep water vessel capability (>10,000' & 300K lbs)
- Riser Release
    - At Lower Flex Joint
    - Increase Pressure Rating of Riser Connection to 10,000 psi
- Hydrostatic Assist to Shear
- Industry Survey of DW Hydraulic Power Unit Capacity
- Deploy Full System Simulator for Containment Training

Regulations

- Use APA Process Rulemaking & Collaboration
- Regulatory requirements focused on major hazards
- Streamline approval for Subsea Dispersant Use, Is Monitoring Required?
- Resolve Containment Qualification Testing

Operations / Standards

- Industry Requirements Capping Stacks
    - Clear Consistent Definition of Containment, including terms of Containment. (API/BSEE)
    - Capping Stack RP to define functionality, Tiered Capping Stacks developed for optimum mitigation (RP Workgroup)
    - Capping Stack RP to define Capability for Top Kill (RP Workgroup)
    - Soft landing Capping Stack (RP Workgroup)
    - Loading and Bending Moments for Capping Stacks
    - Industry Review of Other Containment Scenarios (RP Workgroup)
- RP for Containment Plans/Requirements (Once Requirements Solidify)
- Wellbore Screening Tool / Blowout Risk Assessment JIP (BORA)
- BOP Enhancements
    - Enhanced Shearing Capability, Erosion Resistance and Materials for Severe Service (Subcommittee 16/Std 53 Workgroups)
    - Pressure & Temperature External Monitoring on BOPs (Subcommittee 16/Std 53 Workgroups)
        - Document Mutual Aid Rig Requirements

Communications

- Interagency Communication (EPA, NOAA)
- Industry Group/Regular Meeting to Share Containment Learnings

- Debris Removal – Share info from containment companies
- Community Outreach (Education) including NGOs, Academia on Containment Capabilities
- Create Pre-Identified Technical Experts for Scientific Advisory Panel for Containment Event

Technical Summary of Session #6 – Risk Assessment of Critical Operations and Activities

This section was added after the Workshop to record the Findings and Recommendations that were discussed at the Risk Assessment breakout session. It will be used as the summary.

One of the first discussion points surrounded the fact that Risk Assessment in general is a very broad topic and perhaps too difficult to cover in a general session. As a result, the discussion did not cover all the areas in the original white paper. Nevertheless we did manage to identify some specific findings of general agreement for both the industry and the regulators in this area. In this Addendum we will cover both generally agreed upon findings as well as highlight some important discussion topics that did not necessarily resolve themselves into recommendations.

Item #1:

It was widely recognized that as a result of the Macondo accident, the regulatory body (BSEE) received a considerable amount of external criticism that they were “too close” to the industry. In response to this criticism, communication channels have been significantly reduced. The general consensus of this group was that more communication, not less, between regulator and industry would be highly beneficial. There is a high level of respect between industry and regulator (on both sides); both regulators and industry have contributions to make toward improving safety; and combined efforts are a significant improvement over working in isolation.

Recommendation:

- BSEE should lead the effort to establish a more collaborative approach to working with industry. Dialog between regulators and industry is important to encourage continuous improvement and development of a safety culture and this needs leadership from the top.

Time frame – Immediate

Priority – High

Responsible party – BSEE

Item #2:

Although the BSEE organization (and predecessors) requires reports to be filed for offshore “incidents” there is no such data gathering for “near misses”. Comparative analysis from other industries has largely demonstrated that “near misses” follow many of the same precursors that lead to incidents and a proper analysis to this data would be highly beneficial for reducing the number of incidents. For this to occur, a number of issues surrounding the reporting details (e.g. which data should be reported; what formats should be used; how it should be collected; how should proprietary issues be managed) would need to be resolved, and some data gathering experience would be highly beneficial in resolving these.

While there was not yet a consensus among the group, valuable areas to consider should include “kicks” -- specifically kick frequencies, kick volumes, and kick intensity. Consideration for existing efforts such as the OGP WEC database should also be taken into account. As a first step toward beginning this process the recommendation is not to immediately mandate a solution, but work toward building a collaborative solution with the industry.

Recommendation:

- Encourage (possibly anonymous) reporting of “near misses” (perhaps similar to FAA voluntary program)
  -- Focus should be on identifying trends or patterns to aid in identification of potential hazards, root causes and mitigating factors
  -- Focus on process safety and well integrity
  -- Need to develop clear definition of what should be reported

Time frame – Short Term

Priority – High

Responsible party – BSEE

Item #3:

Each of the industry operator and service company representatives in this discussion noted that their own companies had significant process risk management programs that were (at least internally) considered to be largely effective. It was recognized that these programs can and should always be improved. Even more important than improving any particular risk methodology, however, was the importance of communicating the risks discovered to the workers in the field. There was a strong group sentiment that developing processes and technology for effectively communicating and making risk understandable is currently more important than improving the assessment methodologies.

Recommendation

- Industry should work on establishing processes for effectively communicating results of risk assessments to the workforce

-- The goal is to identify and mitigate hazards (not “check the box”)
-- Communication is more important than developing new tools
-- Need to establish/improve mechanisms to share lessons learned from previous events
-- Risk assessment results and lessons learned need to be disseminated in an understandable fashion.
--The workforce needs to understand cause and effect (“why” as well as “what”)
Graphical approaches such as bow-tie diagrams as discussed in the IADC HSE Case Guidelines could be helpful in this regard.

Time frame – Short term

Priority – High

Responsible party – Industry

Item #4:

One of the few IADC/API documents that provides specific guidelines for risk assessment is API 14J. Although 14J is specific for offshore production facilities and has not been updated since 2002 it forms a good baseline from which to build and expand. This document was seen as a good starting point for incorporating the latest risk assessment technology and upgrading risk practices across the industry.

Recommendation:

- IADC/API should review risk assessment methodologies using ISO documents such as ISO 17776, as references to update API 14J, which offers guidelines for risk assessment.
  -- Develop recommended practice (similar to methodology of API 14J) that focuses on risk assessment of escape and evacuation from offshore platforms and rigs
  -- Need to consider overall risk assessment for integrated production facilities to address interaction between downhole, surface systems, topsides of all structures/vessels involved
  -- Need to consider risk assessment of simultaneous operations between platforms, MODUs, and marine vessels.

Time frame – Short term to get started

Priority – Medium

Responsible party – Industry

Item #5:

The previous recommendation highlights another problem around incident data collection where it has been recognized that due to the non-uniformity of collected incident data, all the data currently needs to be sorted, categorized, and analyzed manually – a time consuming and error prone process. Now is the time to utilize the incident database to help standardize the incident reporting data format and transition it to an automated, computer "friendly" data input process.

Recommendation

- Commission a third party group to develop or adopt a standardized reporting system to facilitate computer sorting/analysis of incident data.
  -- Current system requires manual sorting/categorization of incident reports
  -- Perform a study to clearly define the data that needs to be collected and means of reporting
  -- Commercially available systems may be preferable to brand new systems
  -- Evaluation/analysis of data should be made available as feedback to industry.

Time frame – Short term to get started

Priority – High

Responsible party – BSEE

Item #6:

It was recognized that exercises where multiple companies apply their capabilities in risk management to the same problem are highly beneficial for both the regulator and the industry. Such studies not only demonstrate the state of the art in risk assessment, but can also serve to define agreed upon baselines for further developing and understanding risk assessments.

Recommendation:

- An industry group should come to the DOI with a specific proposal (i.e. defined scope, cost and time estimate, etc.) on a 3rd party study it thinks needs to be funded by the government. This would cover simulated scenario-based risk assessments conducted (similar to DNV exercise commissioned by Norwegian Oil Association OLF).
  Possible scenarios include a hydrocarbon release from a deepwater floating rig, or an analysis of a new technology implementation.

Time frame – Short term to get started

<u>Priority</u> – Medium

<u>Responsible party</u> – Industry (recommended by regulator)

<u>Item #7:</u>

Another important discussion involved the use of Reliability Based Design (RBD) as a strategy for moving beyond current well design strategies based on limit state design. While there was not a formal recommendation, there was a strong sentiment from the group that Reliability Based Design is a widely recognized approach for mechanical design (including well design) and should be encouraged.

Session 1:
Well Control with Surface BOPs

Chair: Brian Skeels, FMC Technologies Inc.
Co-Chair: David Young, Chevron

1. White Paper

General Purpose:

This white paper presents a baseline of the current technology of Surface BOP drilling and its *Effects of Water Depth on Offshore Equipment and Operations*. The paper is meant to provide a brief background of the topic and identify current trends and challenges. This paper is intended to address:

- Current technologies and challenges with implementing those technologies.
- Trends and/or notable technologies envisioned for the near and long-term
- Coordination and communication to help align the efforts of industry and regulatory agencies

This white paper was also prepared and later updated to include discussion points from delegates attending a joint BOEM/BSEE and ANL sponsored workshop, *Effects of Water Depth on Offshore Equipment and Operations*, held in Galveston, Texas November 2-3, 2011. “Workshop Findings” are summations of the discussion points.

Acronyms and Abbreviations:

AADE	American Association of Drilling Engineers
AFE	authorization for expenditure
ANL	Argonne National Laboratory
APD	application for permit to drill (BOEM/BSEE)
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Bull	technical bulletin (API)
CAPEX	capital expenditure
CFR	Code of (US) Federal Regulations
DDCV	deep draft caisson vessel; other citations reference to a Spar
DIV	drilling (or drill pipe) induced vibration
DnV	Det Norske Veritas (Norway)
DP	dynamically positioned (stationkeeping)
HAZMAT	hazardous material (identification and mitigation analysis)
HAZOP	hazard operation (identification and mitigation analysis)
HSE	health, safety, and the environment
IADC	International Association of Drilling Contractors
ksi	1000 psi
MODU	mobile offshore drilling unit (BOEM/BSEE)
Mr/I	bending moment x pipe radius / pipe moment of inertia
NACE	National Association of Corrosion Engineers
NTL	notice to lessees (BOEM/BSEE)
OCTG	oil country tubular goods
PD/2t	internal pressure x pipe outside diameter / 2 x pipe wall thickness
ROV	remotely operated vehicle
RP	recommended practice (API)
SBOP	surface blowout preventer

SID	seabed isolation device (IADC); Other citations refer to it as the environmental safe guard (ESG), or the subsea disconnect system (SDS)
SPE	Society of Petroleum Engineers
SX	saturation exploration
TLP	tension leg platform
VIV	vortex induced vibration
WSD	working stress design
σ	material stress
Ys	material yield strength

Background and History:

The interest in surface BOP (SBOP) systems on floating MODUs has been primarily to find novel ways to drastically reduce the amount of time and CAPEX associated with drilling a well.

The first recorded instance of the use of a SBOP stack on a MODU was in Nigeria on the *Sedco 135* in 1967. Since then, the concept languished until mid-1992 when **Unocal** introduced a radical low-cost strategy for exploration drilling, called Saturation Exploration (SX), in Indonesia. The SX strategy was to drill as many low cost prospects as possible using the same amount of AFE funds that would otherwise drill fewer wells using floating drilling operations involving a subsea BOP stack and low pressure marine drilling riser. By saturating the prospect area with far more wells, the statistical likelihood for success in finding new reservoirs was greatly improved.

The key to SX was to minimize the time to drill each well, use a smaller MODU vessel, and minimize the riser/hardware, both to reduce overall cost. The majority of hardware cost lies with the high pressure riser pipe. To offset this investment, the riser is put to use for the first well, then becomes the casing program for the second well. New casing pipe is then employed as the riser for the second well which becomes the casing for the third well and so on. Unocal realized early on that hydrodynamic forces and drilling wear might limit the riser's practical life. So by limiting the pipe's exposure to one well, and finding a subsequent use for it, reduces overall costs through its double duty.

- The initial program was with an 18 ¾-in. BOP suspended in the moonpool from the *Sedco 602*.
- The second phase utilized a 13 $^5/_8$-in. BOP used from the *Sedco 601* and when additional riser uplift (tension) was required an air can was installed. Using a 13 $^5/_8$-in. SBOP system the *Sedco 601* could work in 6,700 ft water depth.
- The third phase was using the *Ocean Baroness* semi-submersible with and 18 ¾-in. BOP suspended in the moonpool using line hydraulic tensioners.

The other savings initiative was the minimal use of hardware. It was argued that Indonesian waters are relatively benign with respect to metocean conditions. Therefore a moored semi-submersible in these waters would be a very stable platform from which to work, especially if SX drilling time to drill a well was on the order of days rather than weeks (for wells in Gulf of Thailand). From this premise, it was determined that a single string high pressure riser's bending fatigue and tension requirements would be manageable and situations which might lead to damaging to the riser were extremely remote. It was further surmised that an additional well control barrier at the sea floor, a seabed isolation device (SID) (beneath the high pressure riser) was unnecessary (no SID or control system to operate it – further cost savings).

As the nuances of using SBOP drilling and the SX strategy became clearer, **Unocal** was able to work its way up to drilling 16,000 ft wells in less than 18 days.

Since **Unocal** first utilized SBOPs, other operators in 2002-2005 followed suit, including **ConocoPhillips** in China, **Total** and **Santos** in Indonesia, and **Shell** in Brunei, Brazil and Egypt. SBOP capability grew under these campaigns to water depths over 8,000 feet and pressure containment up to 10,000 psi. However, the extension of SBOP capability was viewed by these operators to carry more technical risk, and adopted SIDs to the hardware configuration. Other notable milestones include:

- In 2009 **Murphy Oil** installed a Floating Drilling Production Storage and Offloading (FDPSO) system in West Africa (Azurite project). A SID was deployed during this campaign.
- In 2011 **ATP Oil & Gas** deployed the first in the Gulf of Mexico SBOP/SID drilling system from the *ATP Titan*, a deepwater floating drilling and production facility. The SID is equipped with two blind/shear rams.

As mentioned, the most obvious incentive to using SBOP high pressure riser technology is ***cost.*** The potential to use smaller, less expensive rigs to drill the same well continues to spur interest. There is also the opportunity to increase fleet size by improving a smaller rig's water depth capability. The smaller loads and less volumetric requirements associated with a SBOP's high pressure riser lower variable deck load requirements and riser tensioning capacities of the MODU back within those of second and third generation rigs. The smaller loads and riser diameter in turn makes the SBOP smaller in size and weight and makes it feasible to handle and suspend from the rig's substructure.

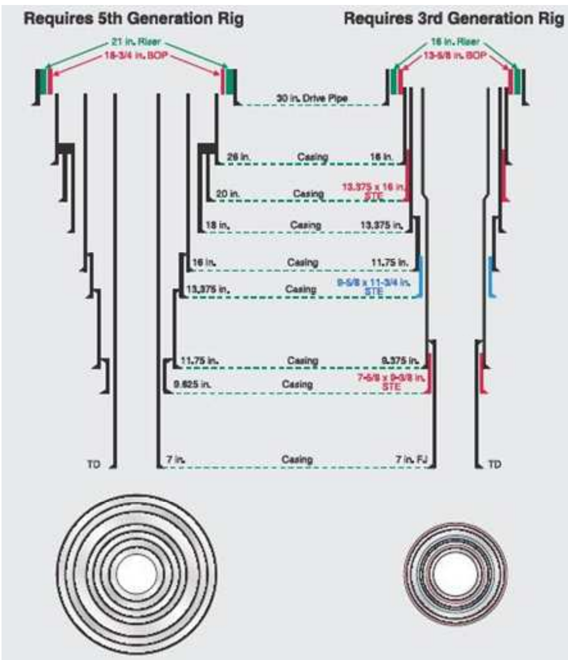
Many operators feel the BOP at the surface rather than on the sea floor means more predictable well control can be handled quickly and safely, since choke and kill lines are shorter (to the SBOP) and boost lines are not needed.

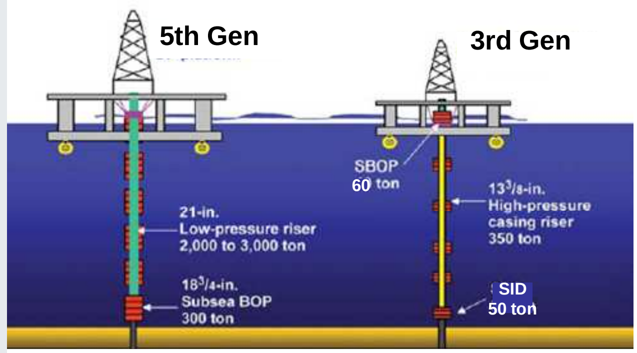
There are some limitations to SBOP, the foremost of which is operating environment. To date, SBOP operations have been conducted in benign sea and weather conditions and containment pressures below 10,000 psi.

Also, the riser diameters in an SBOP system are smaller than the conventional 21-in. marine riser, limiting the hole size drilled and the number of casing strings in the well. Typical riser sizes may range from 10 ¾-in. to 16-in., meaning conventional 18 ¾-in. subsea wellhead casing hangers will not pass through the SBOP or high pressure riser;, requiring special wellheads with smaller through bore and hanger profiles. Additionally, the number of casing strings that can be run in a well may be limited.

With a smaller bore riser system, "slimbore" drilling techniques can be employed, adding to the overall cost savings. But slimbore well design has its limits with respect to reservoir depth and pressure, and using a smaller MODU and high pressure riser may be limited to working in relatively benign metocean environments. The smaller diameter wellbore also makes well completion and flow testing difficult because of the smaller completion string sizes and equipment, both with inherent flow capacity restrictions. This is why SBOP-high pressure riser drilling has been better suited for exploration drilling than production drilling.

So SBOP is not for every possible scenario worldwide.





Subsea BOP vs. SBOP Systems
Approx. 3000 m WD

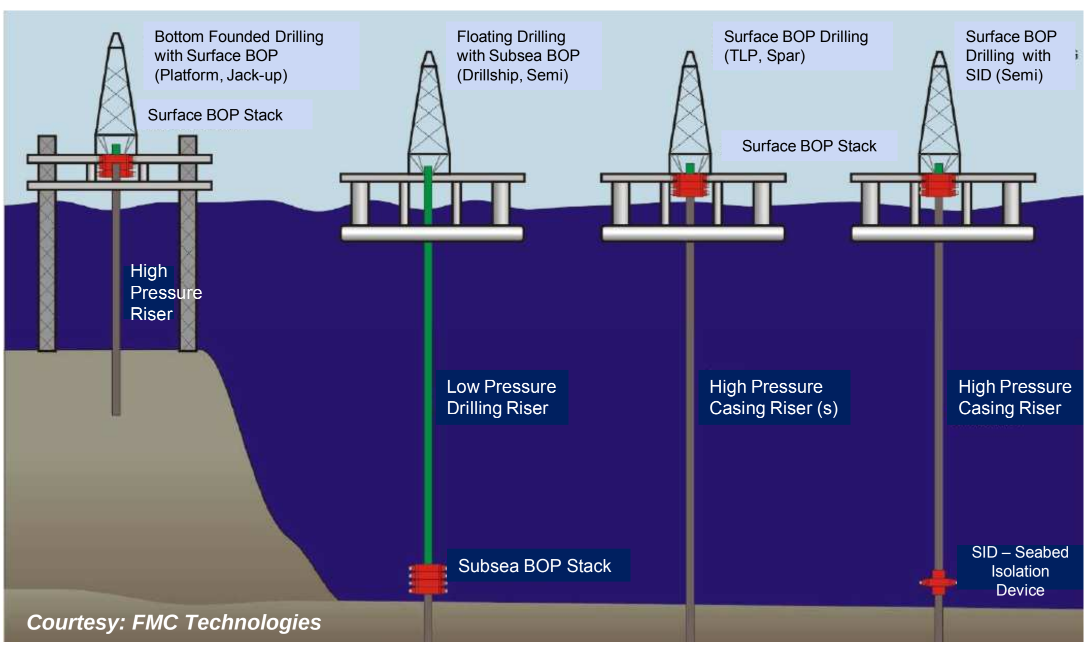
$450k / day	$250k / day

Courtesy: FMC Technologies

The other outgrowth of SBOP drilling technology has been employed as a part of tension leg platforms (TLPs) and Spars. TLPs and spars are floating, permanently moored vessels with deep drafts and a fair amount of tonnage displacement (positive buoyancy). As such they become extremely stable platforms in a variety of metocean conditions. This premise lead to a modified form of the traditional SBOP practices on platforms and jack-ups. In the bottom founded platform design, a new riser string is run and landed inside the previous casing string, as the well gets deeper and the working pressures increase. For TLPs and spars, the number of casing strings that make up the riser is limited to two: an outer environmental barrier riser, and an inner pressure barrier riser. The first dual casing string drilling riser system was first implemented on the **Shell** *Mars* TLP. The minimizing of riser strings to two optimized the hang off weight the floating TLP or spar had to support; allowing the structural draft/displacement of hull to remain within acceptable technical and economical boundaries. The two pipe riser approach is seen as having additional benefits. First, the outer riser serves as a back-up barrier, should the inner riser lose structural or pressure integrity. If there were only a single riser that leaked, the drilling mud below the SBOP would drain out to the environment until enough hydrostatic head was lost to invite a kick from the well pushing wellbore fluids upwards in an uncontrolled manner. Second, the annular area between the two riser pipes could be monitored for any pressure build-up, signaling the potential of an inner riser breach to rig personnel earlier. Third, the two risers separated the loads acting on the system; the outer pipe only seeing environmental loads, the inner pipe pressure end loads. Fourth, the use of SBOP riser technology on dry tree floaters such as TLP/Spar prevents clashing of a subsea BOP with the installed production risers. The use of a subsea BOP, such as was used on the **Shell** *Auger* TLP, required a very large spacing of the wells on the sea floor. This resulted in the need for a lateral mooring system to move the entire platform over the well to be drilled. In the case of a Spar, even though well spacing and lateral mooring is common, the restriction at the keel is very limited. A single pipe high pressure riser sees a combination of both external hydrodynamic loads combined with internal pressure loads. To meet both criteria, the pipe has to be designed with added strength (which usually means added wall thickness – and weight, or the use of higher strength materials, or both) and is more susceptible to fatigue damage because of the cyclic loading at higher amplitudes. In the dual riser case, the cyclic loads acting on the external riser are much less since they are not coupled to the high pressure loads, and the inner pipe is free of cyclic loads altogether since the outer riser pipe shields the inner pipe from the metocean environment. Fifth, the two risers basically constitute the "dual barrier" design rule common throughout the oil industry. With two risers in place, technical risk is minimal to the point where a SID is not required.

The larger vessel draft and riser weight management also affords the drilling engineer the possibility of larger diameter hole access, or higher well count when SBOP technology is used.

SBOP systems also come in three varieties. The traditional configuration for bottom founded structures such as fixed platforms and Jack-up MODUs, a second configuration for moored floating structures such as TLPs and Spars, and a third configuration for Floating MODUs such as semi-submersible MODUs. This paper focuses on the latter two.



SBOP Components *(from IADC Surface BOP Guidelines)*:

The components that make up the SBOP system, described below, are pretty much universal. Some variation of hardware location depends on the SBOP location, the method of handling and riser tensioner attachment and the number of drilling riser strings employed. The descriptions are for equipment starting at the rig floor, working toward the sea floor.

Diverter Adapter

An adapter flange may be required to interface the top of a telescopic joint with the rig's diverter element.

Flex (or Ball) Joint

The flex joint is a low pressure dynamically sealing ball and cup arrangement that decouples the physical alignment between the rig floor, the diverter adapter structurally affixed to the rig floor's structure, and the telescoping pipe below. It usually has a minimum 10 degrees range of operating envelope. The flex joint here is nearly identical to those used in floating drilling operations.

Flex joints are not commonly used on TLP/Spars. Instead, the upper portion of the riser (above water) is held vertically by two sets of roller guides spaced vertically part. The rollers may be found in the riser tensioner frame. For some Spars, the rollers were incorporated with the riser's air can buoyancy system.

Telescopic Joint

The telescopic joint provides a means to allow the drilling fluid to return to the mud pits and guides drilling tools into and out of the wellbore at relatively low pressure conditions. As its name implies, it extends or contracts on itself with the changing relative height between the fixed portion of the drilling riser and the vessel (heave). Its design too is nearly identical to those used in floating drilling operations, except that it is connected directly to the SBOP. Depending on where the SBOP stack is located (below the splash zone or above the splash zone in the moonpool area) will determine the length and available stroke. Sometimes, a purpose built multiple barrel telescopic joint is required to accommodate extremely short stack-up height constraints when SBOPs are closer to the rig floor. The stroke of the telescopic joint should be sufficient to accommodate the design rig offset in the event of a loss of station keeping, and the full range of dynamic motion due to rig motions, tides and storm surge. The outer barrel(s) of the telescopic joint may also be used as an attachment point for the riser tensioner lines either by means of padeyes or a load ring.

Alternative methods of returning the mud to the flow line are possible thus eliminating the need for a telescopic joint. These would include rotating heads, mud return pumps and other means. In selecting and locating these components in the system it is important to determine if they form part of the well control system that needs to contain full working pressure or if they are simply low pressure mud return devices. With alternative mud return devices consideration should be given to observing the well fluid level and preventing fluid spills when no pipe is in the hole and during the passage of large size tools such as bits and stabilizers.

Surface BOP Stack

A minimum of one annular BOP is required in the SBOP system. This is a key component and is the often the first well control device employed when primary control is lost. It also facilitates other well control procedures such as stripping.

If stripping is considered, the closing pressure and stripping surge accumulator configuration should permit stripping without landing off significant weight on the SBOP system. The riser tensioner system must support any weight added. If significant use of the annular BOP is anticipated, consideration should be given to the accessibility to this component for change out of the element. A second annular may be considered but note that this adds weight and height to the SBOP.

In the SBOP configuration ensure that any tension loads in combination with internal pressure and bending are taken into account on the annular flanges and structure.

A minimum of three rams are required in the SBOP stack. At least one of the rams should be configured as a shear/blind ram for closing open hole or for containing an uncontrolled flow in the drill pipe. The remaining rams should be configured to close and seal on all tubular sizes used in the well program.
.
Note that if pipe is hung off on the rams that this weight must be supported by the riser tensioners. Typically it is not feasible to support all the drill pipe weight on the tensioners.

If a SID is used, the shearing requirement may assigned to the SID fitted with shear/bind rams instead of placing them in the SBOP stack. In either case, shear rams should be equipped with means to lock the ram closed in the event of loss of hydraulic supply pressure.

Spacer spools may be required between ram and annular preventers to ensure the proper spacing between the ram preventers, particularly the shear/blind rams. Spacer spools are also used to adjust the height and clearance of the SBOP above the riser tensioner support ring or support frame depending on the configuration. Spools may also be used to provide additional outlets for alternative mud return methods.

In some rig configurations, the SBOP may be installed below the splash zone. If so, additional components will be required. Many of these will be standard subsea drilling riser components. To install the SBOP below the splash zone, the riser must be hung off and the SBOP and stress joints installed in the string.

A significant benefit of this installation method is the ability to retain a full 50-ft stroke on the telescopic joint which may extend the suitability of SBOP operations into more severe environments.

SBOP Connector

The SBOP connector attaches the SBOP to the top joint in the riser string. This is usually a transition or stress joint. The transition joint will have a suitable hub at the top for the SBOP connector to latch and seal. The connector may be a mechanically or hydraulically actuated device.

The connector must contain full wellbore pressures and support the weight and bending imposed by the SBOP and telescopic joint above and riser below. In some cases the connector must also support the entire riser string during installation and the riser tension loads in operation. Selection of a connector shall take into account all tension loads that are to be applied during the handling, installation, testing and operation of the SBOP system.

The loads may be in combination with internal pressure and bending. Physical access to the connector location, personnel safety and handling efficiency should be considered when selecting a connector configuration.

SBOP Choke and Kill Lines

The choke and kill lines may be positioned in different configurations depending on the intended service. These lines are connected to outlets on the ram cavity bodies of the rams within the SBOP (just like land and platform SBOPs are connected). This short distance is one of the SBOP drilling’s advantages over floating drilling operations with a subsea BOP. In floating drilling, the choke and kill lines are extended to the surface via individual (3 or 4 inch diameter) lines strapped to the exterior of the low pressure drilling riser. Should a well kick occur, well control operations dictate circulation and exchange of heavier fluids into the well as wellbore fluids and gasses are passed out. This circulation transfer occurs at a nominal flow rate while the wellbore fluid/gas is in the well below the subsea BOP. As the wellbore fluids enter the choke and kill piping, the cross-section area of the pipe drastically reduces, speeding up the circulation rate, and requiring special well control procedures to be followed during this time. For the SBOP with shorter choke and kill lines, this extra procedure is not needed and simpler well control practices can be maintained the kick is completely circulated out at the SBOP.

Each choke and kill outlet features isolation valve(s) rated for the full SBOP working pressure. Due to the limited access to the SBOP the choke and kill valves are typically hydraulically operated.

Tapered Stress Joint for Single Pipe High Pressure Riser

The connection point between the SBOP connector and the high pressure riser is an upper tapered stress joint. At the top, the joint has an upset lip with either a flange or clamp hub to allow the SBOP connector to structurally lock and seal around. Below the upset lip, the riser pipe features a thick walled cross section, which tapers down thinner and thinner until it reaches the nominal wall thickness of the rest of the riser. It provides a connection between the riser and the SBOP and controls stresses and in particular bending and fatigue at the top of the riser string. The tapered stress joint is uniquely designed to withstand the increased bending stresses induced in the riser pipe as it sways from a lateral offset (from ocean waves and current) to a forced vertical orientation with the SBOP stack. The wall thickness increases with the increased bending moment, keeping the cross sectional stress in the pipe the same.

Upper and lower tapered stress joints are employed at the top (under the SBOP) and the bottom connecting to the top of the SID, to control bending moment induced stress as the riser pipe is “forced” back into a vertical orientation. Use of tapered stress joints replaces the flex joint used between the subsea BOP stack and the low pressure marine drilling riser. Flex (and ball) joints are very efficient means to de-couple bending moment loads in the riser to structurally founded end connections, but are also very low pressure designs, unsuitable for high pressure riser SBOP applications. Tapered stress joints are more common on subsea completion/workover risers and rigid production tieback risers on TLP and spar well completions. These high pressure riser designs and their tapered stress joints are manufactured in accordance with API 2RD or 17G.

Surface Wellhead (alternate to a tapered stress joint) for Single Pipe High Pressure Riser
In some case the connection between the riser and the SBOP will be by means of a wellhead rather than a tapered stress joint. This is generally used in cases where a smaller riser is run through a larger SBOP. The wellhead is installed on the bottom of the SBOP which in turn is set below the rotary prior to casing riser running operations.

The high pressure riser pipe is run through the SBOP and eventually lands a load shoulder designed end coupling (hanger) to a landing shoulder within the wellhead body. After landing, the hanger engages a surface element between wellhead and the supporting wellhead hardware. If a surface wellhead is used it must contain full wellbore pressures in combination with riser tension and bending loads. Particular attention should be paid to potential movement of the hanger and seal inside the wellhead due to riser, SBOP and vessel movement. Any small movement of the seal could cause a seal failure so the seal and landing surfaces must be correctly centralized and laterally constrained within the wellhead.

Surface Wellhead for Dual Pipe High Pressure Riser
TLP and spar SBOPs are connected to a purpose-built wellhead body that performs three functions. First, the wellhead has the requirement and features for a landing shoulder design found in the single riser design through which it passes the inner drilling riser pipe and shoulders its hanger. Second, the wellhead’s exterior features a hub or flange bottom end connection which is attached to the upper tapered stress joint of the outer drilling riser. The wellhead is designed with same rated working pressures to withstand either the inner or outer pressure ratings. Third, the wellhead body features an annulus access outlet and isolation valve for monitoring and venting the annular space between the two riser casing strings.

The wellhead is installed between the upper tapered stress joint and the bottom of the SBOP. Once the SBOP is secured, the smaller inner riser is run through the SBOP.

SBOP Handling and Riser Tensioning
The configuration of the SBOP is closely dependent on the handling and tensioning method. The following are the main methods for handling and supporting the SBOP.

- Tension from the top - In this case the SBOP and riser system is supported from the top through a structural frame constructed around the SBOP stack, or by means of a tension ring on the telescopic joint. If any tension and bending loads are transmitted through the SBOP flanges the combination of internal pressure, tension and bending must be considered.

- Tensioning joint (or ring) – In this case the SBOP frame only has to support the weight and movement of the SBOP; not the riser. The riser is tensioned through separate tensioner lines connected to a specialty joint with a swivel ring (tension ring) and padeye/shackle connections. Alternatively the riser tensioners may be attached to a load bearing frame (in which case careful attention should be paid to the load transfer method from the frame to the riser to ensure that all components are independently supported).
- SBOP installed below the splash zone – In this case, the SBOP stack itself must be capable of fully transmitting the riser loads through the SBOP body (rather than through a structural frame) and flanges or this must be accomplished by a load bearing frame that isolates the SBOP from tension and bending loads. Above the SBOP will be a flex or stress joint and a cross over to marine riser. Several marine riser joints perhaps some with buoyancy will connect back to the rig. A conventional telescopic joint and riser tensioner attachment may be used. Note that on older or shallow water rigs adapted for SBOP service the riser and telescopic joints may not be rated for the higher tensioner loads in deepwater SBOP operations.
- For TLP/Spars, direct acting hydraulic-pneumatic riser tensioners (hydraulic cylinders directly attached to the riser) are the most commonly employed. These tensioners couple the riser directly to the deck structure.

Seabed Isolation Device (SID)

The seabed isolation device (SID) is intended as a back-up device to seal the wellbore and disconnect the riser. As such, it is not considered as a primary well control device.

The control system for the SID should comply with API Specification 16D and API Standard 53. In particular, the control system should incorporate a means to continuously monitor and display accumulator pressure. For moored vessels, a single set of controls, and ROV intervention capability, rather than dual, independent controls specified in API Specification 16D is considered adequate for SBOP applications. For SBOP operations from DP vessels, consideration should be given to dual, independent controls as specified in API Specification 16D. The control system for the SID could comprise a number of different options all providing redundancy should the primary system fail.

It is likely however that any system designed will only require one control system at the seabed. The SID control system subsea accumulators may be provided with hydraulic power replenishment by means of an umbilical (hot line) strapped to the casing riser or from a ROV pump package and fluid reservoir. The system should be designed in such a way that the controls will both open and close the shear ram and the riser connector. In normal operation the SID will be operated only for connecting and disconnecting from the well. This may be powered by the ROV. Emergency operations will commence should the riser fail or the SBOP control systems fail to operate. For DP rigs, should the DP system fail the SID will be the primary means for shearing the drill pipe, sealing the wellbore and disconnecting the riser. Consideration should be given to the use of deadman, auto-shear and emergency disconnect functions should the riser need to be disconnected in a stationkeeping emergency. The auto-shear and emergency disconnect should perform in a required sequence to secure the well and release the riser in a timely manner to avoid damage to the riser or other MODU equipment.

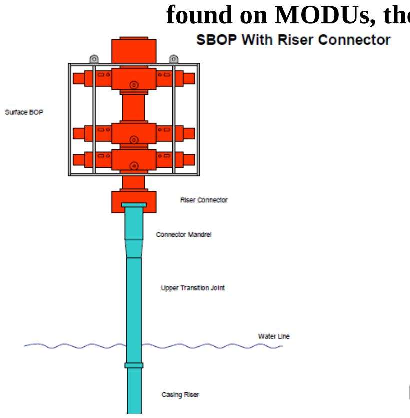
The SID configuration contains two subsea connectors and at least one shear/blind ram all manufactured in accordance with API 16A. The upper connector is an emergency disconnect connector that locks and seals around the upset lip of the high pressure riser's lower tapered stress joint. The connector may be unlocked to release the riser in an emergency situation where riser angle or MODU position over the well is compromised to the point that the SID must be closed and the riser released to head off any collateral damage to the subsea well, or the riser and rig above. The shear/blind ram is there to close the open wellbore and shear drill pipe if in the well when the emergency arises. A second subsea connector oriented downward locks and seals to the high pressure housing of a smaller bore subsea wellhead. Note that for a SID, the subsea well must be of the subsea wellhead design with a high pressure housing, internal casing hangers and annular packoff assemblies manufactured in accordance with API 17D. All of the well's casing strings have to be hung off and sealed inside the subsea wellhead's high pressure housing below the SID's ram. Casing strings cannot contiguously run up to the SBOP since the SID has no casing shear capability.

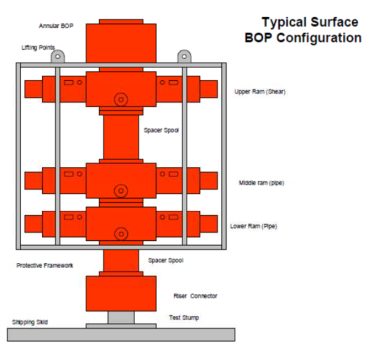
All three components in the SID are designed to withstand anticipated tension loads in combination with internal pressure and bending.

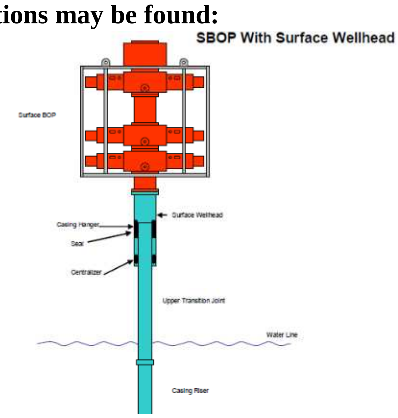
In some instances, a second pipe ram is added to the SID above the shear ram. This added ram may be used in conjunction with the re-installed high pressure riser and a drill pipe (rams closed around the drill pipe) to assist in circulating a gas pocket underneath the SID's shear ram after a disconnect event, and well control through circulating drilling mud needs to be re-established before drilling can continue.

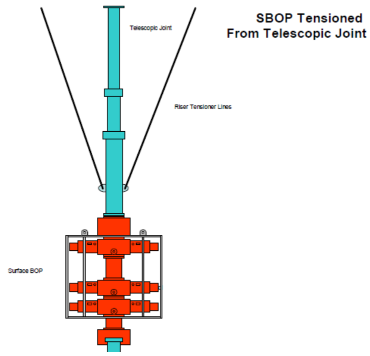
Note: The seabed isolation device (SID) has been called (in other citations), the emergency safe guard (ESG), or the subsea disconnect system (SDS).

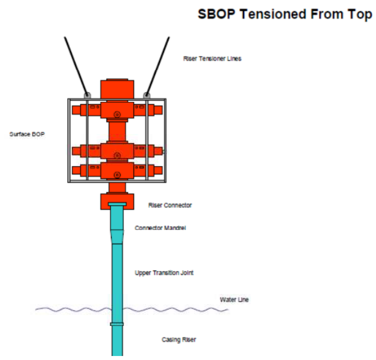
For tensioning support suspended from the derrick's substructure over a large open moonpool, commonly found on MODUs, the following tensioning configurations may be found:

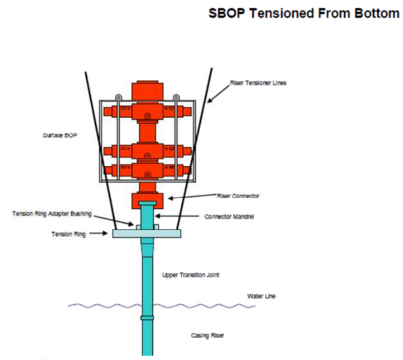


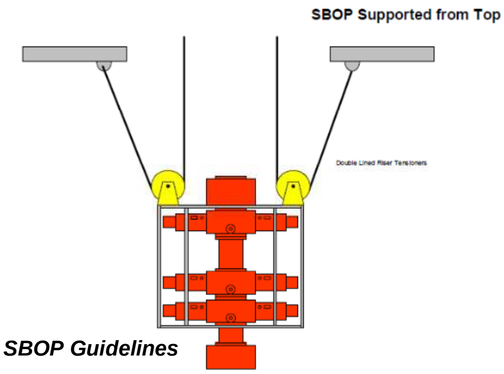




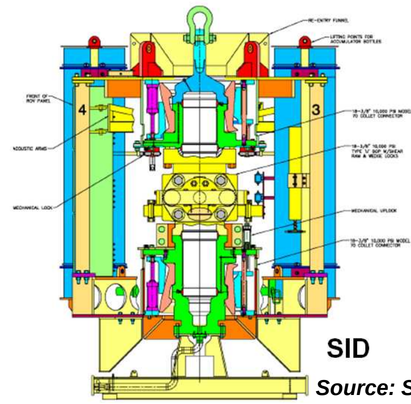






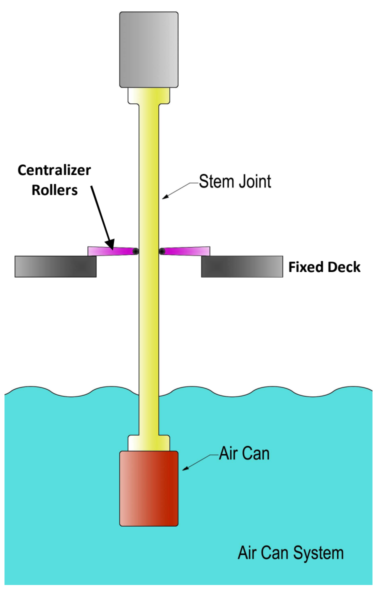


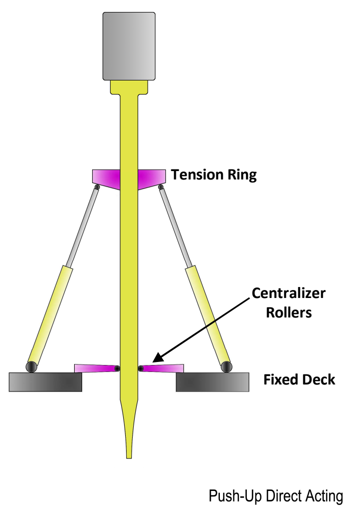
Source: IADC SBOP Guidelines

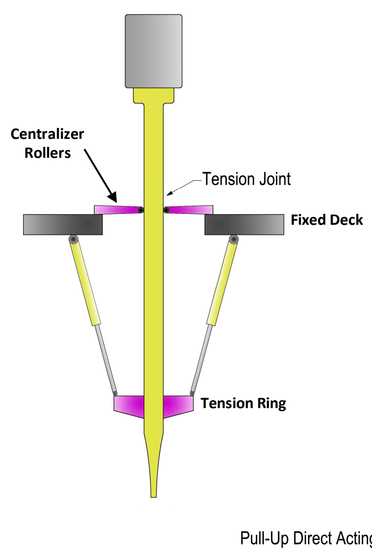


Source: SPE 87108

For fixed (cellar) decks that surround each well slot instead of a large open moonpool, commonly found on TLPs and Spars, the following tensioning configurations may be found:

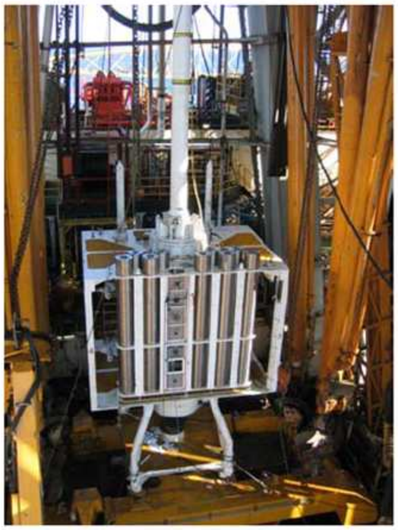






Courtesy: GE Oil & Gas

Effects of Water Depth on Offshore Equipment and Operations
Topic #1: Review of Surface BOP Equipment and Operations



Surface BOP (SBOP) shown with Riser Tensioner and Tension Ring (Stena Tay) →

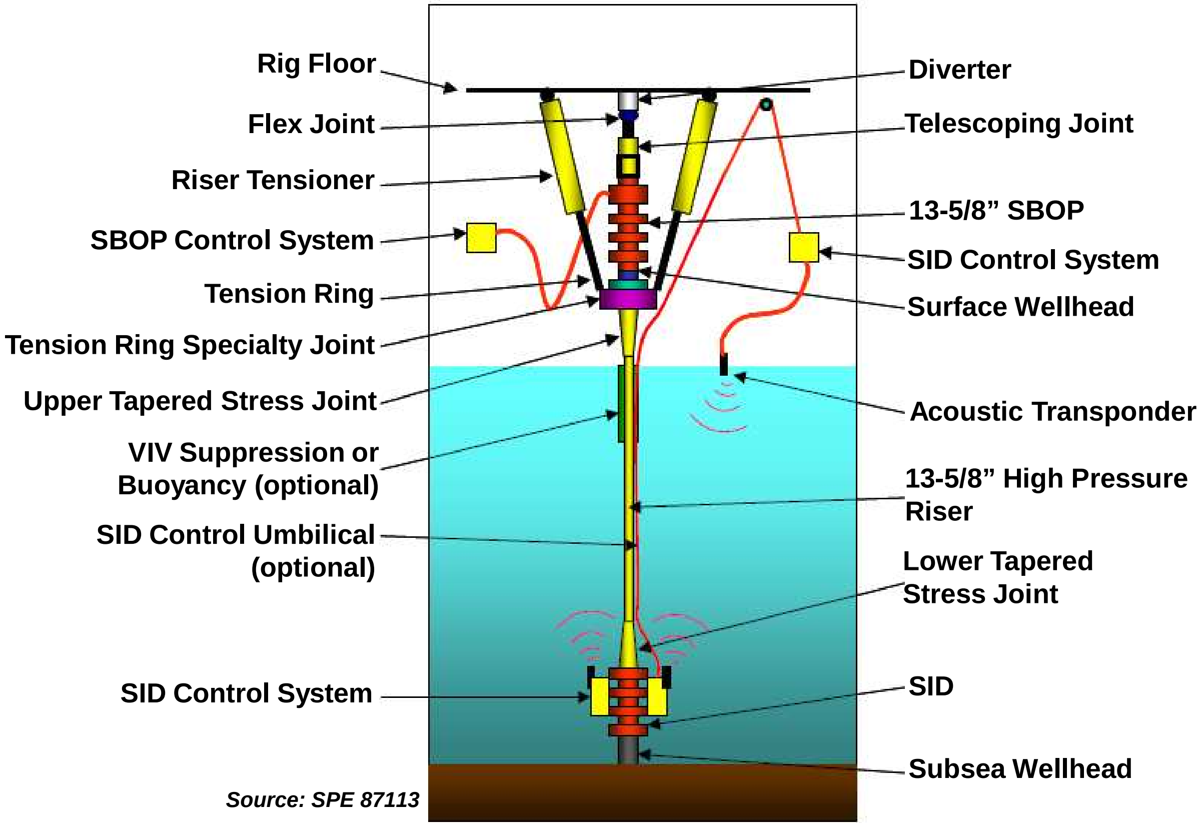
Subsea Isolation Device (SID) shown in Moonpool ←

Source: SPE 87113

Titan – Floating Drilling And Production Facility ←

Titan's Subsea Isolation Device (SID) lifted off a workboat →

Source: ATP Oil & Gas Website



Source: SPE 87113

Reference Standards:

Government Regulations and NTLs:
- 30 CFR 250 Subparts A thru S
- NTL drafts t-256h and t-259c on SID, June 2011
- NTL 2008-G07, 2008-G09, 2009-G10, on managed pressure drilling and hurricane fitness

Industry Standards:
- API Specifications 16 A-C-D-E-F
- API Specifications 6A, 17D
- API Specifications 5CT, 5L
- API RP 5C1, 5C2
- API Bull 5C3, 5C5
- API RP 2RD
- API RP 2SK, 2T
- DnV OS-F101, OS-F201, OS-E301, on pipeline, dynamic risers, and mooring designs
- API RP 17G
- API RP 17H
- API Standard 53
- API RP 59
- API RP 64
- API RP 90, Annex C
- API RP 96
- API RP 1111
- NACE MR0175
- IADC SBOP Guidelines

- NORSOK D-010

Engineering Bulletins and Brochures:

- Cameron ESG
- *Stena Tay*
- Helix *Q4000*
- Ocean Riser Systems
- 2H and Subsea Riser Systems
- Weatherford Managed Pressure Drilling Services

Issue #1 – Is it still worth it? – Pros and Cons:

Offshore operations Surface BOP operations is the traditional time tested standard when evaluating hardware and practices associated with land and fixed platform well control operations. Floating drilling operations were developed to offset the dynamic effects and cyclic loads associated with vessel movement, by moving the BOP and wellhead to the sea floor, away from the vessel motions, and then further isolate this equipment by adding flexible joints that decouple bending moments which otherwise build tremendous stresses at either end of the riser pipe. However the trade off for structural stability is the operational lag time and excessive pressure drop/area reduction associated with extra long choke and kill lines and control system umbilicals. In addition some deepwater oil and gas reservoirs are located in areas with narrow margins between pore pressure and fracture gradients or in shallow formation depths below the mudline. Well control using floating drilling operations are far from ideal under these conditions. Surface BOP operations for deepwater floating drilling and access activities are more straightforward, because of the simpler and shorter lines to the BOP (and less onerous hydraulic characteristics).

Other advantages of SBOP operations in deepwater include:

- Larger vessel watch circles are possible for drilling envelope (but very short watch circle distance for shut down and disconnect)
- Far less mud is required (18 ¾-inch bore vs. 13 $^{5}/_{8}$-inch bore)
- Less chemicals needed and consequently less HAZMAT exposure
- Less exposure to heavy lifting and tensioning requirements
- Less waste requiring disposal
- Less risk of gas expansion in the riser
- Reduced risk of hydrate formation
- More efficient hole cleaning characteristics (better mud circulation characteristics and less need for a booster line)
- Smaller riser diameter changing VIV and DIV characteristics
- Smaller rigs required, extended use of fleet capabilities – more availability
- Ability to use rotating control head on top of the SBOP to utilize managed pressure drilling techniques through tight pore/fracture pressure zones common in deepwater

But raising the BOP from the sea floor wellhead to the surface moves the risk to the high pressure pipe in between. Should anything happen there, there are few options left to regain control of the well. So far the solution has been to either: utilize dual concentric drilling riser strings, employ a SID to close in the well and disconnect before emergency conditions manifest themselves. In addition, the high pressure riser must deal with a unique set of design and operation issues associated with dynamically supporting the BOP structure in air, the combined pressure and environmental loading acting on the riser pipe suspended in the water column.

Many will argue that SBOP has its place given the right circumstances. Although its use has been in relatively benign metocean environments, it has been demonstrated to be useful in more severe conditions, provided sufficient HAZOP and additional safeguards (such as a SID or dual riser strings) are employed with the full understanding operating within the technology limits of the high pressure riser pipe.

A Different World

The SX program had to deal with a couple of blowout wells during its campaigns in the Gulf of Thailand; exposing the vulnerability and riskiness of SBOP drilling without some sort of contingency in place. Since then, the safety-conscious and blowout-averse culture of today demands a complete HAZOP review identifying all contingency plans and mitigation hardware. As a result, SBOP-high pressure riser systems since 2000 either feature: a dual string drilling riser, or a single high pressure drilling riser with a SID.

Hurricanes Ivan, Katrina, and Rita also pointed to MODU mooring vulnerability. Rigs that utilized permanent or preset moorings survived and stayed on location. However these three storms destroyed 10 jack-up rigs and sent 24 jack-ups and semi-submersibles adrift or foundering on shoals. Metocean return period storm criteria had to be revised downward by almost an order of magnitude; resulting in new mooring systems designed nearly twice as strong. DnV OS-E301, API 2SK, and 2T may need to be reviewed in concert with tight watch circles needed for adequate high pressure riser operation.

These added constraints further limit the locations and economic viability of SBOP-high pressure riser drilling to a smaller niche of opportunities.

Issue #1 – Workshop Findings

All of the delegates pretty much agreed with the pros and cons presented. They agreed that the moving of the BOP from the seafloor to the surface does indeed simplify well hydraulics and response time, not to mention simplify personnel training and operations. However the overwhelming issue that trumped everything else is the metocean criteria and the offshore facilities structural and mooring capability. It was cited that most MODUs and their mooring equipment are typically designed around a 10 year recurring storm. Anything stronger, and the MODU needs to initiate storm temporary abandonment operations to secure the well and move the rig out of harm's way or to a safe harbor. It was also noted that Spars and TLPs are typically designed around 100 year recurring storm criteria, as these rigs are designed to remain and weather the storm. In addition, retrieval of conventional subsea drilling riser takes roughly takes 1 day to install (or recover) 760 meters (2500 feet) of riser deployed. A single string high pressure riser would take more time to "break" out all the couplings/casing pipe threaded connections, bits than their subsea riser counterparts. A dual string drilling riser even more time. Since hurricanes can spawn in nearby warm waters, threats have to be dealt with within 4-5 days.

This is considered too much of a threat to maintain the integrity of any high pressure riser from a MODU that has to run from a storm (even with a SID). Spars and TLPs are better suited to SBOP and drilling riser operations since their hull and moorings are designed to ride out the storm.

It was also cited that a SBOP/high pressure riser advantage not mentioned earlier, was getting into tight (high well count) clusters beneath a Spar or TLP. In multi-well scenarios, there possibly could be a considerable number of wells with producing risers extending from each well to the surface. Getting a subsea BOP in among these wells to an interior well site (say for a remedial workover) would be difficult at best to avoid riser clashing and at worst collision damage. This might be alleviated somewhat by spreading the wells further apart on the sea floor, but in turn spreading them too far apart makes access from the Spar or TLP more difficult. By keeping the BOP at the surface eliminates these spacing issues.

In summary, SBOP drilling from a MODU is not recommended for US waters, unless it is demonstrated that the MODU could shelter in place to ride out a 100 year storm. (One delegate wondered why a Spar MODU couldn't be built with suction anchor technology to meet these challenge; entirely possible technically, questionable commercially). Spars and TLPs, especially those with multi-well platforms are much better suited for SBOP/high pressure riser operations.

Issue #2 – It's all about the riser:

The primary technical limitation of SBOP drilling technology is the load management and metallurgical properties of the high pressure pipe. Because of the high pressure containment requirements below the SBOP, typical flex and telescoping joints are used in the riser design. Instead tapered stress joints are used to deal with bending and lateral loads at constrained locations at either end of the riser. Their tapered wall thickness is calculated to grow commensurate with the corresponding increase in resulting stress as one gets closer to the fixed constraint. Hence, the tapered design and its end connections are designed around an assumed maximum limit of metocean conditions and vessel movement that in turn dictates the window in which the MODU can safely operate.

A further constraint is the material that physically makes up the high pressure riser joints and how they're fabricated and connected. It is easy to assume that the higher the loads and stresses imparted on the riser, higher strength materials should be employed. However, there are metallurgical and fabrication limits. High strength materials are uniquely susceptible to embrittlement and stress cracking when exposed to corrosive media such as hydrogen sulfide or salt water (chloride) infused fluids. Higher strength materials are more prone to premature failure under these conditions. Steel mill techniques that form pipe, have increasing manufacturing problems maintaining a uniform wall thickness and concentricity as wall thickness increases relative to pipe diameter (D/t ratio). If the thickness and ovality tolerances are too lax, the pipe may be prone to external pressure or buckling collapse; too tight and the manufacturing costs associated with scrap rates will make it too expensive and scarce.

Material selection must be made as to whether it is a "NACE" (sour) or "non-NACE" environment, as defined by NACE MR-01-75. As a general rule of thumb, carbon steel grades with yield strengths on the order of 80,000 psi (or lower) are less susceptible to embrittlement or stress corrosion cracking. Higher material strength, increased temperature, or cyclic loading may exacerbate the problem. Heat treatment or work hardening steels to increase strength (σ) makes the pipe stronger but also makes it more prone to embrittlement failure. If one restricts material strength, $\sigma = PD/2t$ dictates a greater wall thickness (t) is required to withstand the pressure (and environmental) loads; hence the design conundrum. Increasing material strength increases the likelihood of metallurgical failure; increasing wall thickness increases overall weight, reduces the accessible bore available for drilling, and reduces either water depth or deck load capacity of the MODU. The only other alternative is going to a more exotic alloy that provides higher strength while resisting embrittlement (cracking) failure. Unfortunately their raw material cost may be an order of magnitude higher than carbon steel and they are usually more difficult to fabricate (threading, welding, forming [forging, drawn over mandrel, etc.]).

Some have argued that the exposure to a sour (or H_2S environment) is a time dependent function and the detrimental effects of stress cracking can be mitigated or controlled by limiting the pipe's exposure through chemical scavengers in the drilling mud, restricting load conditions or just lowering the overall useful service time (similar to **Unocal's** limit of short drilling times and using the pipe one time). However, this strategy may involve an excessive amount of monitoring and data collection activity beyond what's practical on the rig; not to mention how accurate or accessible the data has to be in order to make appropriate assessments when to curtail the riser's use.

Dual Riser Pipe Configuration – Divide and Conquer?

A dual riser pipe design in a sense splits the loads acting on the overall system. The outer pipe is inherently larger in diameter and as such can withstand higher structural loads ($\sigma = Mr/I$), while limited to lower pressures ($\sigma = PD/2t$). That's okay in this instance since the inner riser which is smaller is shielded from the structural loads (outside) and is better equipped to deal with higher pressure loads inside. By splitting the loads, each pipe string deals with less combined stress, thereby making wall thickness and ovality issues less severe. In addition the environment is also split. To the outside, sea water is the corrosive agent acting on the outer pipe, while wellbore fluids are contained and dealt with inside the inner string. It is not uncommon to have two different materials, with differing coatings, make-up connections and methods of construction customized for the specific riser pipe string. HPHT raises another interesting point. The inner riser may see much higher temperatures (in addition to pressure) relative to the outer riser, adding thermal growth into the design mix.

As mentioned earlier, other drawbacks to a dual pipe drilling riser include: the added weight per foot of riser itself, the increased support requirements imposed on the riser tensioners, plus the added complexity to hardware design, running and operating procedures. These plus the added stiffness associated with locking two concentric pipes (greater moment of inertial (I)) make the riser much less compliant. Therefore the watch circle of the MODU has to be restricted so as not to overload the riser tensioner or the subsea wellhead from excessive loads. For these reasons, dual pipe drilling risers are better suited for TLPs and spars.

Large Bore wells vs. Slimbore wells

One last dual string riser configuration needs to be mentioned. As mentioned earlier, SBOP-high pressure drilling evolved from the notion of using a smaller casing approach to save time and consumables in drilling the well. Yet some of the larger TLPs and Spars have sufficient displacement capacity to support larger bore (more conventional) casing well programs. The most common approach starts with a nominal 21 inch outer riser string (similar to the marine drilling riser used in floating drilling) with a pressure rating up to 3000 psi. Then large casing (at lower pressure ratings) are installed through the outer riser with either a 21-$^{1}/_{4}$ 3ksi BOP or an 18-$^{3}/_{4}$ 5ksi BOP for well control. This allows standard casing hangers to be run and set while keeping the wellbore large for deeper drilling depths. Then as the well is drilled further and higher pressures are encountered, the second inner high pressure riser is installed with an adaptor and a 13-$^{5}/_{8}$ 10ksi BOP. This involves splitting the stack, but keeps hardware weight down and is easier to handle. Subsequent casing strings land in either nested casing hangers, or a liner hanger down hole. The next most common method is to use an 18-$^{3}/_{4}$ 10ksi BOP and run everything through it. This has the advantage of not having to split the stack and allowing standard hangers to be used for all strings. However, the BOP is much heavier and running operations and equipment is more complex.

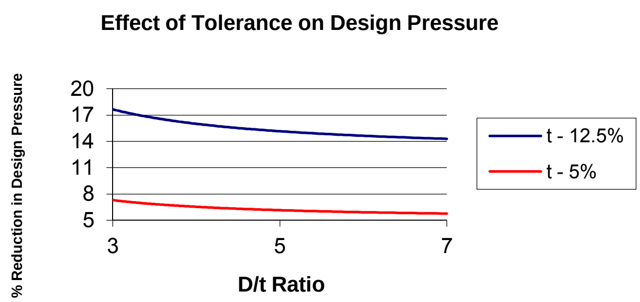
Which Code to Use – Is there another way?

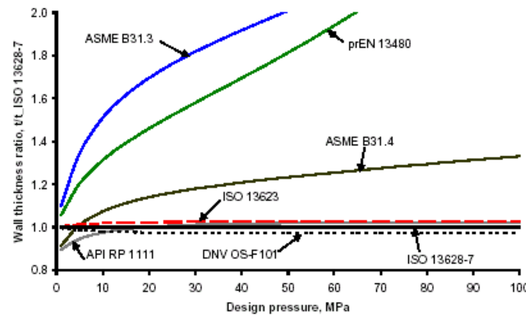
The SBOP drilling riser is often deemed “rigid high pressure piping”, and therefore subject to the design codes commonly used by the oil industry for piping design (ASME Pipeline Design Codes – B31.3, B31.4 and B31.8). But the pipeline design guidelines are based on quasi-static design conditions, not dynamic. And wall thicknesses are based on 67% and 83% of material yield strength for normal operating and test pressure conditions. API 16Q addresses marine drilling risers; but its design philosophy assumes short-duration exploratory drilling. So there are no provisions for fatigue limiting criteria or safety factors for extended drilling. Rather it focuses on extreme and survival conditions, resulting in a very conservative design.

API 2RD takes another step closer to the SBOP riser case and has become more prevalent design code in the Gulf of Mexico, partly because it has been written for the production risers, but more importantly that, “the design of risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) requires recognition that risers form a subsystem that is an integral part of the total system.” Its design methodology still uses the conservative approach of allowable stresses based on a percentage of yield strength. But API 2RD eases the design restrictions by employing multiple working stress design (WSD) limits for different load cases (normal operating – 67% of Ys, pressure test – 90% of Ys, and survival – 100% of Ys). This allows the allowable stress to be higher in low probability events, maintaining conservative calculations without driving to a single over the top condition. API 2RD is the most widely accepted steel riser code in the industry, and it is the required code for riser design in the Gulf of Mexico referred to by BOEM/BSEE.

However, there is another design philosophy whose acceptance is growing, especially in Europe, “Limit State” theory. Pipeline design codes DnV OS-F101 and API 1111 use Limit State theory for deepwater pipeline designs when ASME pipeline codes values lead to pipe designs that no longer make sense from either from an installation or on-bottom in-situ case. DnV OS-F201 has a similar design method for dynamic risers, and uses Limit State API 17G for designing completion/workover risers that access subsea wells.

Limit State theory follows the same stress calculations as WSD, but sets its acceptance criteria based on two design criteria: a "pipe-burst" failure mechanism (ultimate limit state) and a serviceable limit state (the traditional "leakage" or pressure loss criteria). Both Limit State and WSD formulas closely track to one another at low pressures. However, at higher pressures, their results diverge, with WSD providing a more conservative result than what is actually required and observed from pipe failure testing. API 17G is accepted as the standard for high pressure workover and completion/workover risers and are finding their way into light duty and limited sidetrack drilling applications in the North Sea. So it might be argued that API 17G might be a plausible alternative to API 2RD. Government regulation has been silent on accepting Limit State, as an alternative to WSD, making this a relevant discussion point.





A second criterion that is becoming more and more crucial to deepwater riser design is the wide band of allowances in manufactured geometry (wall thickness, ovality, etc.). Much of oil country tubular goods (OCTG) follow the criteria established in the API 5 series of specifications (5CT, 5L, etc.). OCTG manufactured to API 5CT allows variations in wall thickness up to 12-1/2% below the nominal thickness. For most well and static pipeline applications with high D/t pipe ratios (i.e. thin walled pressure vessels), reductions in design pressure rating remain relatively constant around 14%. However as D/t drops below 8 (the range needed for riser applications), the reduction in pressure rating increases by an additional 2-3%. Normally, the 14-17% reduction in strength can be offset by increasing wall thickness. But adding wall thickness causes all sorts of collateral design problems. However, narrowing OCTG tolerances by half nearly doubles the pressure rating performance. Similar improvements in reducing ovality and pipe straightness allowances gives the riser designer more room to optimize pipe thickness for the best possible riser weight and load support.

SBOP drilling differs from conventional floating drilling operations in that the well control components (i.e., the BOP stack) are not located at the seabed. Instead, the BOP stack is located at the surface just below the drill floor of the MODU. A further key difference is the SBOP drilling riser is designed to contain wellbore pressure whereas a conventional marine riser does not contain wellbore pressure and is isolated from wellbore pressure when the BOPs are closed.

There are numerous standards and guidelines for conventional drilling operations. Some of these cover many parts of the SBOP system design, configuration and operation. However, there are at present no SBOP specific guidelines that the industry can use in the planning and implementation of an SBOP operation. Consequently, the approach to SBOP operations within the industry has been driven by specific circumstances, individual operator requirements, and by IADC's SBOP guidelines.

Issue #2 – Workshop Findings

The delegates saw the advantages of limit state theory analysis and its advantages of addressing multiple load scenarios (pressure, tension, cyclic bending components of hydrostatic loading) that European codes and API 17G afford. Also noted were the improved performance benefits afforded by adopting the tighter tolerance of milled OCTG to API 17G rather than the API 5 series of codes. Other codes such as API 16Q were seen as being inappropriate for SBOP applications. The discussion soon boiled down to the realization that API 2RD is probably all that is needed, with a couple of simple suggested modifications. As mentioned, API 2RD employs multiple working stress design (WSD) limits for different load cases. For single string risers, this practice has served the industry well when designing and operating them in both drilling and production modes. However 2RD is silent on the dual riser string configuration. Therefore, it was recommended that an added section address the WSD for dual bore risers as follows:

- When the first (external riser) is deployed, the well is being drilled at shallower depths and with larger casing strings inside. Therefore the normal operating – 67% of Ys, pressure test – 90% of Ys, and survival – 100% of Ys, applies for the lower expected wellbore pressures.
- When the second (internal riser) is deployed, the inner riser now assumes the role of pressure containment – 67% of Ys, and pressure test – 90% of Ys, but doesn't have to deal with external environmental loads and lesser cyclic loading; simplifying its overall design criteria.
- When the second (internal riser) is deployed, the outer riser now assumes the role or shielding environmental loads – 67% of Ys, and "accidental pressure containment" – MASP = 80% of Ys (should the inner riser leak or some other sort of breach occurs). The outer riser can take into account fluid head for internal pressure containment and external ambient seawater pressure when considering the resultant pressure load acting on the riser during this event.
- Adopt the tighter mill tolerances of OCTG found in API 17G to improve performance and encourage weight reduction.
- API 17G addresses design and qualification of other well control equipment and cyclic loading qualification in addition to tubular goods, which may prove helpful in system design. 2RD only addresses tubular connection qualification and may want to refer to 17G to address other equipment.

In summary, API 2RD and 17G are considered satisfactory for designing SBOP high pressure risers. Load limit state and WSD design theory is seen as equally applicable. The WSD method in 2RD has proved adequate for the majority of Spars and TLPs up to now, and there doesn't appear any reason not to stray from this current preference. However, there are a few suggestions for improving 2RD to make it more universally practical for production *and drilling* (especially dual bore) applications. API 17G focuses on single bore high pressure riser applications and is more practical for *workover* applications, but it is recommended for specification/qualification of other well control equipment.

Issue #3 – Other Issues:

Other specific discussion points at the workshop included:

(o issue or question, • workshop findings)

- o What is the recommended number of rams; what type and in what order for the SBOP and SID? If a shear/blind ram is put on the SBOP, could a fish drop and damage the SID barriers?
  - 3 to 4 rams on the SBOP as is conventionally done; blind, shear, casing (changing out sizes during drilling or using variable bore rams for drilling program). SID should have 1 or 2 blind/shear rams (keep its functionality to a minimum).
  - Dropping a fish on SID not an issue; close SID after a certain period of time; no changes to SID envisioned.
- o For design purposes, what pressure should be used within the ram wellbore? The current requirement is for the maximum anticipated surface pressure (MASP) – typically for a SBOP, but what should that be for the SID?
  - MASP, same pressure rating equipment for both SBOP and SID.
- o What is mechanism for regaining well control over a shut in SID with gas? With hydrocarbon liquid? (dealing with bottoms up effect) (Murphy Azurite considered a pipe ram in addition to a shear/blind ram (dual stack) as part of its lessons learned).
  - Standard well control practice of circulating out a kick from anywhere in the well should be used. Riser and SBOP should be circulated bottoms-up with appropriate weight mud, and then open SID to release "bubble" and continue SBOP circulation well control operations. No need to modify or change SID with any extra equipment or lines.
- o What is the most cost-efficient, yet safe control system for the SID? Electro-hydraulic multiplex? Acoustics, "Deadman" systems, ROV intervention, ROV hydrophone? If acoustics for SID control, how does one deal with the noise and shielding associated with a blowout plume?
  - Acoustic telemetry – electro hydraulic control with hydraulic accumulator bottles. Two backup systems should include ROV intervention primarily to recharge accumulator bottles, and battery powered "deadman" logic system should communication with the surface be lost. Consult with API Std. 53.
- o API 17H "high flow (HF)" receptacles with 1" bores have been specified for the subsea ROV interface. Hydraulic lines between these stabs and the function may be smaller and more restrictive. Is this right standard? Should there be hydraulic isolation to the disabled control system to prevent back flow?
  - This is a possible add on to SID hardware, but simplicity is the operative word. Consult with API Std. 53. Some see there needs to be more than just a single hot stab for each

function – an isolation feature and a hot stab function.

- What types of MODUs are going to be allowed to use SBOP? Moored vs. DP vessels? TLPs/Spars only? What will be the allowed high pressure riser configuration for these (dual string, single string – SID)? Is there a water depth preference? Where should "Deadman", auto-shear, and emergency disconnect functions be required for these configurations?
  - SBOP design is not recommended for MODUs unless designed to weather 100+ year storms. OK for Spar and TLP. Single string or dual string design is OK provided there is an adequate HAZOP to identify and mitigate potential well containment issues. SID is only seen as another tool in Operator's kit to choose from and use as part of well containment/control strategy – it's not a mandated requirement. SID deployment may be a problem when well spacing or interior well access is required (as was mentioned about subsea BOP access).
- Are there different maintenance and protocols associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment?
  - SBOP may use simpler land and platform based BOP operation and maintenance procedures and hardware. SID only has emergency close and open functions; far less than anything required for subsea BOP.
- Are there different reliability and redundancy requirements associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment? How does one determine the efficacy level for maintenance of other SBOP/SID well control equipment?
  - SBOP should follow established land/platform based protocols and studies should use established reliability/redundancy values for this equipment; same for maintenance, etc. This should be entirely separate and unrelated from subsea BOP protocols/reliability/redundancy values and practices.
- Are personnel easier to train in operating, maintaining and use of well control equipment for SBOP-high pressure riser drilling than Subsea BOP and floating drilling operations?
  - SBOP is seen as easier to grasp and teach than floating drilling/subsea BOP practices.
- Are personnel currently trained in operating the high pressure riser and monitoring its performance in the metocean environment?
  - A mute point if the vessel has 100 year storm survivability. After a severe storm event, most equipment should be inspected for storm damage and visible or suspect equipment taken out of service for additional inspection or rework.
- How does one inspect for premium threads and couplings during make-break and re-use? Are re-cuts required? Can they only be re-used once and only in a static condition (like SX)?
  - Not addressed since make-breaks are seen as minimal (if ever) associated with Spars or TLPs. Standard thread inspection practices from Operator and manufacturer considered adequate.
- How does one determine the fatigue life for maintenance of high pressure riser?

  - Follow practices in API 2RD or 17G.
- How does one determine the fatigue life for maintenance of subsea wellhead? Are there any well foundation design or subsea wellhead rigid-lock requirements?
  - Follow practices in API 2RD.
- Is IADC's *SBOP Design Guidelines* adequate for all other aspects of SBOP planning and operations? Should there be separate guidelines for shallow water vs. deepwater? Should there be separate guidelines for TLP/Spar vs. MODU?
  - No need for specifics with respect to deepwater; deepwater practice should be the same as shallow water.
  - SBOP/high pressure riser should be modified to include dual riser string configurations.
  - MODU SBOP can be continued to be mentioned, but noted it is not recommended for US unless MODU can shelter in place for a 100 year storm.
- Should Standard 53 address SBOP-high pressure riser drilling? Does RP 96 properly address SBOP-high pressure riser drilling with respect to well design?
  - Not specifically addressed. Current codes appear to be adequate with respect to SBOP configurations.
- Are there different well survivability issues (using the BOEM/BSEE well screening tool) that should be addressed in HAZOPs because of the SBOP-high pressure riser drilling?
  - No; screening tool is adequate.
- What should be done to address and minimize the effects of mechanical wear on adjacent production risers next to the drilling riser in the case of TLP/Spar well spacing?
  - Current riser pipe clashing analysis methods well established and adequate for job. Obviously well count, riser size and numbers, well spacing, water depth, metocean data, etc. will all play roles in design and analysis.
- What are the current mechanisms for aligning the Industry and the Regulatory Agencies?
  - Discourage use of SBOP for most MODU operations in US waters. Augment API 2RD for dual riser pipe applications. Use API 17G, 53 where practical.
- Gaps in regulations, standards, industry practices, collaboration and technologies.
  - IADC guideline may need to be "upgraded" to recommended practice (RP) status to work toward a minimum acceptable level of reliability. IADC to donate to API?
  - Industry has good "managed pressure drilling" well control simulators; no additional work needed.
  - Well control computer simulators are not configured or available to address SBOP and SID; only SBOP only or subsea BOP only.
  - Capping stacks that are being developed for subsea BOPs may not be useful for SBOP applications, so smaller stacks may be needed; a new configuration may be needed to deal with Spar/TLP deployment and for close well spacing applications.

Final Remarks and Recommendations:

To summarize the position paper on surface BOP and high pressure riser configurations for deepwater activities, the following is offered as a suggested plan of action:

- A NTL should be written and issued by BSEE on SBOP practices on what types of vessels will be allowed in U.S. Federally Regulated Waters. Specifically, to prohibit MODU drilling with a SBOP unless the MODU vessel and its moorings are designed to shelter in place, surviving the metocean conditions associated with a 100-year return storm. SBOP drilling and workovers would be permitted from production Spars and TLPs, provided their hull, structural, and mooring design meet or exceed the above storm conditions. It may be worth noting that a Spar MODU may be considered for SBOP operations, provided it passes storm survivability design parameters. The NTL should also clarify the minimum requirements for: number of rams, ram designation, choke and kill function outlets/locations, and choke-kill line isolation valve (single, remotely-operated) configuration, and high pressure riser configurations (i.e. single or concentric dual riser designs).
- Draft NTLs t-256h and t-259c on SIDs should be completed and issued by BSEE on SID configuration and usage. Basically, the SID is seen as a hardware augmentation to assist in the efficient connection and disconnection of the high pressure riser to a subsea wellhead. It may be used as part of a lessee/operator's plan to drill, complete or operated a well at their discretion and their intent included in their APD or APM. Suggested ram configuration requirements, i.e. one or two ram cavities, blind or blind-shear rams and no need for choke-kill outlets/lines should be included. It should also be cited that the SID is not considered a testable barrier like a subsea BOP, and as such is outside the scope of a BOPs function testing requirements. A SID will not have to have an "automatic mode function" such as a "Deadman" unit or other auto fail close functionality. Combinations of surface umbilical control, ROV access/control, or remote hydro-acoustic control with hydraulic power accumulation is recommended. It will have to undergo periodic body pressure testing as a part of the SBOP and high pressure riser to demonstrate well integrity, but ram functionality is left to the discretion of the lessee/operator. It should also be noted that the SID's envelope size may prove difficult to maneuver in amongst closely spaced wells and risers.
- API's Committee on Standards for Oilfield Equipment and Materials (CSOEM) - subcommittee 17 should consider updating RP 2RD to add text on drilling operations and dual concentric bore risers in its design guidelines along with the suggested design factors of 67% and 80% for different operating periods of the external riser. In addition, RP 2RD should add text on the structural support and motion compensation of a SBOP, taking excerpts donated from the IADC SBOP Guidelines and Spar/TLP designs.
- API's CSOEM - subcommittee 17's task group on capping stack and subsea well containment should consider capping stack configurations that address accessing a broken high pressure riser (single or dual string) and close proximity well spacing situations. BSEE should monitor the task group's progress and issue appropriate regulation citing the work once it is completed.

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Session 2:
Well Control with Subsea BOPs

Chair: Frank Gallander, Chevron
Co-Chair: Tony Hogg, ENSCO

1. White Paper

Effects of Water Depth on Offshore Equipment and Operations
Topic #2: Well Control – Subsea
(Subsea BOP, Scope is the wellhead and above)

Background Information:

Within the industry there seems to be a state of confusion. Further to that point, the confusion is expanded with some of the ambiguous language that have been introduced either from within the industry standards, introduced regulations or company guidelines, just to name a few.

Part of the focus of the discussions in the BSEE workshop should look at the various documents that are in use and search for the gaps, misinterpretation and/or ambiguity and seek clarity, where possible.

Several documents are going to be referenced in the workshop and may add some value in meeting the objective. More specifically the workshop will look closely at the recently released NTL's, Drilling Safety Rules and Recommendation from the September 14 BOEMRE Report Regarding The Causes of the April 20, 2010 Macondo Well Blowout.

Other documents may also be used and shared within the group, to provide guidance to meet the broader objective.

- Government Regulations and NTLs
- Industry Standards
- Manufacturing Engineering Bulletins, Technical Alerts or other public documents
- Company Guidelines / Policy / Standard Operating Procedures

General Purpose:

This white paper presents a baseline for discussions for subsea BOP drilling systems and the *Effects of Water Depth on Offshore Equipment and Operations*. This document is meant to provide a brief background of the topic and identify current trends and challenges addressing:

- Current technologies and challenges with implementing those technologies
- Trends and/or notable technologies envisioned for the near and long-term
- Coordination and communication to help align the efforts of industry and regulatory agencies
- Human Factors in safety (e.g. training and procedures)

For the purpose of discussion, deepwater will be defined as: ***"a drilling and/or completion operation that is performed from a floating vessel or structure"***.

Scope:

Identification of technical challenges / limitations for subsea well control systems and operations, specifically subsea blowout preventers, control systems (primary, secondary and emergency) and the ancillary equipment that support them, are as vital to the successful

Deepwater Drilling Operations, as the people, (processes, procedures and training) that operate them.

As an integral part of everyday operations, special consideration should be taken to include marine well containment, (w.r.t. the inspection and recovery techniques) has now become equally important as the other many challenges that we face daily.

This document will focus on all of the equipment installed above the subsea wellhead / tree assembly interface to the diverter, including riser tension / recoil and any associated secondary and/or emergency systems, as they pertain to well control.

Introduction:

This desired outcome of the discussions should provide some insight into how well control equipment is managed and the methodologies used, as they are related to:

- Equipment (maintenance, inspection, testing, training)
- Operating Procedures (maintenance, inspection, testing and uses / limitations)
- Emergency Response (processes, training, procedures and risk assessments)

Another desired outcome could be to develop common language that might be useful to BSSE in their development of CFR's and industry in developing standards, to help the end users focus on the intent and not just the words of the documents.

Efforts shall be taken to discuss and analyze specific requirements and frequency of inspection, testing and optimal configurations for the following systems to include but, are not limited to:

- Diverter, diverter lines and valves (although not considered well control equipment)
- Riser
- Subsea BOP
- Control Systems
- Well Containment

To achieve the object of this workshop, several perspectives are provided below to give insight into what individuals are asking themselves about the issues we routinely face, on any given day.

BSEE Perspective:

> *This paper does a great job in reflecting the many regulatory challenges faced by both the industry and the regulator. It is good that some of the "technical" NTLs will be discussed. There is inadequate guidance in the Code of Federal Regulations for MASP, single bore production risers, HPHT, and other operations or equipment. Therefore the regulator has to issue NTLs for clarification. Many of these NTLs are guidance documents and may not be enforceable regulations. Likewise, industry standards are*

lagging behind the advanced technologies, so there is a regulatory void that both regulator and operators are trying to fill the best they can:

- *The regulators - by offering guidance via NTLs and taking a conservative stance with a case-by-case approvals rather than standard approvals.*
- *The operators – sometimes moving ahead and spending money on new technologies only to find out that the Federal authorities may, in fact, not approve a project due to the risks involved.*

BSEE's regulatory perspective consists of balancing prescriptive and performance-based regulations. In addition BSEE regulations allow the use of alternate procedures or equipment so long as the alternate procedures or equipment proposed for BSEE approvals provide a level of safety and environmental protection that equals or surpasses current BSEE requirements. (30 CFR 250.141).

The need to balance prescriptive and performance-based regulations arises because:

- *Performance-based regulations may impose excessive costs on industry in the search for ways to meet regulatory standards.*

- *Small businesses may simply prefer to be told exactly what to do, rather than incur costs to identify steps needed to achieve a performance standard.*
- *This "guidance" effectively takes the form of prescriptive standards that performance standards are supposed to replace.*

Performance standards present fewer implementation issues in cases where actual performance can be evaluated and verified. However, for rare and catastrophic events, performance cannot be measured directly and instead must be predicted, making implementation more difficult.

BSEE uses a hybrid approach that may minimize some of the weaknesses of both design and performance standards. Instead of choosing between prescriptive and performance-based regulations, BSEE uses a blend of instruments. The approach is to require specific technologies or designs, but to add to the regulation "equivalency clauses" or provisions for alternative compliance mechanisms. These provisions effectively allow industry to "opt-out" of the prescriptive standard if they can demonstrate that they can achieve a comparable level of performance or better through other means.

Equipment Manufacture Employee Perspective:

Since the Macondo incident, there has been confusion in regards to requirements for inspection, inspection frequency and certification of equipment. Regarding shearing, there has been confusion about terminology, and what is required to certify that the shear rams are" fit for use". This workshop has the potential of establishing guidance and direction that can be implemented consistently without going through the rigorous *processes that may be required in developing government rules, company policy and industry standards. In addition, first hand exposure will provide more clarity and better understanding of the requirements.*

Well Control SME Perspective:

Attending a workshop like this will provide a venue to connect with various parties involved in well construction process. It broadens ones prospective on how stake holders are inter-related with each, and provide a chance to know requirements of customers.

Currently many industry initiatives are going on, this workshop will help in defining and calcifying the efforts needed to stay safe and compliant with upcoming changes. This would be a collaborative effort where sharing information and knowledge will benefit all participants.

Drilling Contractor Employee Perspective:

Every serious opportunity for Contractors, Operators, OEMs and Regulators to get together to discuss our business should be embraced by each of us. Sessions such as this are, or should be, instrumental in guiding us all forward to achieve our individual goals in a safe and efficient manner.

One size will never fit all, but cross party workshops can go a long way to ensure that all, or at least many, points of view are considered when creating minimum safety, equipment, operational and training standards.

Operator Employee Perspective:

There is value in holding a workshop like this because it is a great opportunity to get operators, mfgs, drilling contractors, third party suppliers, licensing or certifying authorities, industry organizations and regulators together in one room to focus on one objective and develop verbiage that is useful immediately.

Since the Macondo incident, there have been multiple efforts from multiple fronts. This workshop has the potential of establishing guidance and direction that can be implemented consistently without going through the rigorous processes that may be required in developing government rules, company policy and industry standards.

Attending this workshop should provide me with the insight into the processes of; training personnel, operational well control procedures, manufacturing and inspection / maintenance of the equipment and methods for the introduction of new technology into the industry.

If this work session objectives are achieved, the outcome has potential to produce significant results between industry and regulators.

Analysis

At the recent Offshore Compliance Forum (OCF), there were several presentations providing some insight related to subsea BOP issues.

One presentation specifically (Session #2) dissected "***THE DRILLING SAFETY RULE - An Interim Final Rule to Enhance Safety Measures for Energy Development on the Outer Continental Shelf".***

Given the breadth and scope of the requirements, it was difficult to determine what were the actual requirements requested?

Another presentation (Session #5) focused on subsea BOP's while other presentations / discussions addressed other industry actions taken since the Macondo incident. During the discussions attendees were informed about the details of the work, specifically the Joint Industry Task Force (JITF), API standards, industry committees (OOC, COS) and other organization efforts on a global scale (OGP, etc.).

When all of the efforts noted above are taken into account, the opportunity for a thorough analysis could be performed and the objectives of this workshop would be achieved.

Findings

To retain the momentum coming out of the OCF, attendees of the BSEE workshop should take into consideration the work presented and apply those discussions where possible. As a result of the discussion from this workshop, there is potential of coming away with:

- Current status and clarification on Industry standards
- Clarification and better understanding of regulatory requirements, w.r.t. well control systems
- New ideas, procedures and "paths" being utilized by others with industry
- A better informed community in understanding the how important interaction and cooperation between regulators and industry

Session 3:
Well Drilling & Completion Design and Barriers

Chair: Jim Raney, Anadarko Petroleum Corporation
Co-Chair: Ken Armagost, Anadarko Petroleum Corporation

1. White Paper
2. Addendum to White Paper #3, Information on Collapse Design and Burst Design

General Purpose

This white paper on "Well Drilling and Completion Design and Barriers" is one of six papers used to initiate discussions in breakout sessions at the November 2-3, 2011 BSEE/ANL/Industry workshop on the *Effects of Water Depth on Offshore Equipment and Operations*. This final version of the white paper has been updated based on the discussions at that time. It provides background on the topic and identifies current trends and challenges in this area.

This paper addresses:

- Current technologies and challenges with implementing those technologies.
- Trends and/or notable technologies envisioned for the near and long-term
- Coordination and communication to help align the efforts of industry and regulatory agencies
- Human factors in safety (e.g. training, procedures)

Scope

The topic of Session #3 is the design of deepwater drilling and completion programs for wells utilizing subsea wellhead/BOP systems and those drilled and completed from floating facilities such as spars or TLPs using surface wellheads/BOP equipment. The discussion includes the implementation of these programs (the well construction process) and the validation and monitoring of the barrier system during well construction. Note: In this document, deepwater well operations are defined as "drilling and/or completion operations that are performed from a floating vessel or structure."

Organization

This paper begins with an overview of the well design process. From this foundation, the document identifies and discusses existing technical, operational and regulatory challenges associated with the design and construction of deepwater wells. Additionally, consideration is given for the challenges associated with the progression of Gulf of Mexico well construction into deeper higher pressure environments and into deeper water depths. The findings of this white paper are summarized at the end of the document. These findings were topics of focus in the development of this white paper and in the workshop discussions.

NOTE: Superscripts in this document indicate a comment has been made by BSEE during the development of this document. These comments can be found in Section E.

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Introduction

Life cycle well integrity is a principal objective in the design and construction of deepwater wells. In the context of the well construction process, life cycle well integrity can be defined as the *"ongoing control and containment of formation fluids and pressures as the structural elements and barriers of a well are progressively installed."* The need for well integrity begins with the drilling phase and continues through the completion and production phases. Well integrity remains an important issue even after the wellbore is permanently abandoned.

Wells are designed for the specific geological environment in which they will be constructed. The structural components of a well, such as the wellhead and casing, must be designed with the strength to resist the loads that will (or could reasonably) be placed on them in that specific environment. Components are, therefore, designed with sufficient strength to address all loads encountered during the construction process (installation, drilling, well control, and completion), subsequent production operations, and ultimately when abandoned. In addition to strength, all of the structural components must also possess the metallurgical or physical properties required to provide reliable service in the installed environment. Industry recognized standards are used to ensure the integrity of the design, manufacture and the QA/QC of the equipment, tools, tubular goods, barriers, and materials used to construct these wells.

The Well Design Process

The well design process begins with an understanding of the environment in which the well will be drilled. Interpretations of local geologic structure, geo-pressure and formation strengths are developed. These interpretations may be derived either from local drilling experience or from seismic data. It should be noted that uncertainties will exist in the interpretation of the data and ultimately in the description of the geologic environment. The quality of geologic predictions (e.g., pore pressure, fracture gradient, bottom hole temperature and pressure, formation fluids, H_2S, CO_2, chloride concentration, etc.) often relies on the amount of control within a given area. As such, these predictions are usually expected to be more reliable for development wells than for exploration wells. However, for drilling operations in established deepwater fields, the pore pressure and fracture gradient often demonstrate variability due to production.

With a description of the geologic environment in place, constraints are then introduced by the designer to address specific well requirements. These include the directional drilling objectives and the required well depth. Production or evaluation requirements dictate the hole size desired at total depth. Depending on the geographical location, some wells will require an additional surface casing string for the isolation of shallow water or gas flows.

It is common for deepwater Gulf of Mexico wells to penetrate long sections of salt. In some locations, the salt will provide a higher fracture strength which may reduce the number of casing strings required to reach the ultimate well objective.[1] The presence of salt in other locations may present drilling challenges such as shear/rubble zones, inclusions, or abnormal pressures within or around the salt. These troublesome zones may offset the benefits of the increased fracture strength of the salt, possibly increasing the number of casing strings required.

Additional location-specific factors are considered. Zones that may prove troublesome in drilling operations are addressed in the design. These trouble zones might include lost circulation intervals, faulted or mechanically destabilized zones, plastic or chemically sensitive formations, abnormally or sub-normally pressured zones, and intervals that have been pressure depleted (or charged) by production. In developing the casing program, the designer must also consider the presence of hydrocarbon-bearing intervals and any depleted or flow zones requiring isolation. When drilling in mature deepwater fields, additional casing strings are often required to isolate highly pressure-depleted zones with associated low fracture gradients.

Typically, if no trouble zones exist within a drilling interval, casing is set when the mud density required to safely manage the formation pressure approaches the fracture gradient of the weakest exposed formation (normally at the previous casing shoe). Casing may also be set based on geologic considerations.

Other design constraints are not specific to a well location. For example, in all deepwater wells, the casing sizes that can be used in the portion of the well drilled with the riser installed are constrained by the inner diameter of the riser, BOP and wellhead system.

Well design is further limited by high-pressure wellhead housings (HPWH) that typically provide only three casing hanger profiles. For deep drilling applications, or where the pore and fracture pressure margin is small, more than three casing strings are often required to reach the geologic objectives. This requirement can be addressed with supplemental hangers below the HPWH, drilling liners, and tight-clearance casing designs.

Certain technologies have been developed to aid in the conservation of hole size and the reduction of the number of required casing strings. These include flush or semi-flush casing connections, expandable casing, and managed pressure drilling (MPD) technologies such as continuous circulation systems, ECD reduction devices, and dual gradient drilling. Note: the wellbore containment requirement, often affecting collapse pressure, is expected to reduce the shallow applications of expandable casing technology.

Tight-clearance casing programs necessitate the use of hole enlargement devices such as under-reamers and bi-center bits. The hole enlargement process adds mechanical and operational complexity to the drilling process and can reduce drilling efficiency. These tight clearance casings require centralization within the enlarged hole sections to provide uniform annular clearance in preparation for cementing operations. [2]

In addition to these factors, the capacities and capabilities of the drilling rig must also be considered. Floating drilling rigs have water depth ratings that are largely defined by the limits imposed by the marine riser loads (i.e. both the weight of the riser, as well as the over-pull required to maintain the proper riser tension). Also, the load capacity of the derrick and hoisting equipment limit the weight of casing that can be deployed by the rig. These rig capacities are not easily upgraded.

Environmental and Operational Loads

Over the life of a well, the wellhead system may be exposed to many different load conditions. During the well design process, wellhead fatigue risks are assessed based on operational and environmental conditions expected during both the construction and long-term production phases. Wells in areas having harsh metocean conditions or wells that are intended to be operated with a marine riser or production riser installed for extended periods of time (such as wells tied back to a TLP or spar) have an increased potential for damage or failure from long-term fatigue loading.

Wellhead loading conditions with the riser connected during drilling and non-drilling operations are to be considered, particularly with regard to potential damage to the wellhead system as a result of drift-off or drive-off (the loss of MODU station-keeping).

The wellhead system design must also account for the installation of a subsea tree or capping stack (adding the height and weight of a tree or emergency BOP stack).

Considerations for fatigue-resistant wellhead system design (including wellhead connectors and wellhead extension casing joints) may include the following:

- pre-loading the high-pressure/low-pressure wellhead housing interface
- a high capacity subsea tree connector
- placement of the first connector below the sub-mudline point of fixity
- connectors with optimized stress concentration factors
- special care in wellhead, casing, and connector material selection and in the quality of welds
- specifying surface finish requirements for post-weld grinding for the wellhead extension to minimize the potential for crack initiation
- special inspection criteria for weld or materials to minimize the potential for defects that could become crack initiation sites
- pipe alignment to address ovality
- ensuring adequate, as welded, wall thickness

Casing Design

Regulatory requirements must be considered as casing points are identified and load cases are developed during the well design process. Regulations specify the required casing design load scenarios for well control operations. For example, 30 CFR Part 250.413, requires that the well designer establishes the maximum anticipated surface pressure (pressure at the wellhead) in the design of each casing string during the drilling, completion, and production phases.

Each casing string must be evaluated for the loads that will be encountered during the life of the well. Software is available that will help the designer identify casing that will have adequate strength to withstand the stresses imposed by tensile, compressive, bending, torsion (if applicable), buckling loads, burst and collapse pressures, thermal effects and combinations thereof. The well construction process can adversely affect casing strength. Factors such as casing wear must be considered when designing casing programs.

Annular pressure build-up (APB) associated with wellbore temperature changes during drilling and production is a special design consideration for deepwater wells. The elevated pressures corresponding with increased temperature in a closed annulus can impose collapse loads on the inner string and burst loads on the outer string. Special provisions are made in the design, construction, and operation of deepwater wells to address this issue.

Traditionally, a 'working stress' design approach has been used in the design of casing.[3] With this method, safety factors have been adopted for axial, burst, collapse and tri-axial loads to ensure that each casing is fit for purpose. Alternatively, reliability-based design approaches, routinely used for structural design in other industries, have been used in recent years to ensure that casing meets the application requirements.

As a part of the Drilling Safety Rule, the proposed casing and cementing designs must be reviewed by a Professional Engineer, who must certify that the casing and cementing programs are appropriate for the purposes for which they are intended. Once certified, the casing design must be submitted as part of the application for a permit to drill, as required in 30 CFR 250.415(b).

Barriers

Barriers are either physical or operational elements incorporated into the well design to provide integrity throughout the life of the well. They isolate pressures and prevent unwanted movement of fluids within the wellbore and casing annuli. Some barriers are used temporarily to facilitate various well construction processes. Other barriers are installed permanently to be used during the full service life of the well. The use of barriers is regulated by the BSEE for all aspects of well construction.

The barriers used in well construction have been identified in API RP-96 (currently in draft), API RP 65, and API STD 65–Part 2. They are classified as being either physical or operational. Physical barriers can be hydrostatic, mechanical or solidified chemical materials (usually cement). Operational barriers, such as BOPs, depend on human recognition and response. When combined with properly designed, installed, and verified physical barriers (see Fig. 1), operational barriers significantly increase well integrity and reliability.

A hydrostatic barrier is a fluid column of known density that exerts a pressure exceeding the pore pressure of a potential flow zone. Depending on the well construction operation, this barrier can be achieved with a column of drilling fluid, cement spacer, liquid cement, water, packer fluid, completion fluid, or a combination thereof. The qualities of a hydrostatic barrier, including height and density, can change with time, affecting the pressure it exerts. For example, when cement hydrates (hardens), it loses its hydrostatic effect as it transitions from a liquid into a solidified physical barrier. Also, over a period of time under static conditions, high density weighting material can settle from a drilling fluid or cement spacer, leaving a column of lower density base fluid to counteract the pore pressure. These changes must be considered in the design process to ensure that the barrier is effective for the required period of time.[4]

Mechanical barriers are designed to provide environmental isolation within the wellbore or in annular spaces. An acceptance criterion should be established to verify the integrity for each barrier. The greatest level of verification of a mechanical barrier is to pressure test to the maximum expected differential pressure in the direction of the potential fluid flow. To test a barrier in the direction of the anticipated flow, the hydrostatic barrier is reduced to establish the required "negative pressure differential." However, it is often not possible to qualify a barrier to this highest level. In these instances other methods of verification have been established as illustrated in Figure 1 below.

Ultimately, the objective of using and managing barrier elements is to ensure well control is always maintained. The proper design, installation, testing and management of these elements are all critical processes. Some aspects of barrier management are specifically addressed in regulations (The Drilling Safety Rule). These aspects include:

- Two independent tested barriers across each flow path during completion activities – Note: This requirement will be clarified in upcoming regulations. The reference here to "tested barriers" is not to infer that they are to be "tested barriers" as defined in Figure 1.
- Proper installation, sealing and locking of casing and liners
- BSEE approval before displacing to a lighter fluid
- Enhanced deepwater well control training for rig personnel

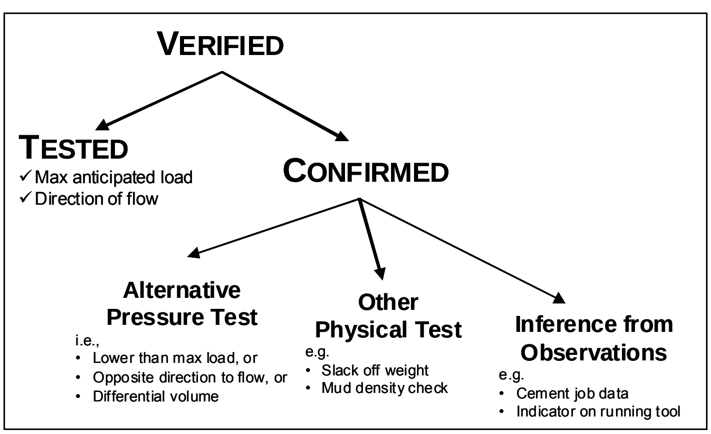

Figure 1 – Barrier Verification Categories (from Draft API RP 96)

Analysis

A) Current Technologies & Challenges Implementing those Technologies

Question 1: What Challenges Exist in Casing and Equipment Design for Deepwater Wells?

1) Well Containment Design Requirement

FINDING: The WELL CONTAINMENT design requirement (addressing structural risk), as currently defined by the BSEE, is very conservative from a well control perspective. The requirement, based on a low probability well control event, has led to well designs that add operational risk, limit design options, and exceed operational requirements. Operators believe that the risk of lost containment can best be addressed (avoided) with proactive process safety rather than structural safety measures. It is recommended that alternatives to this design criterion should be considered by the BSEE on a case-by-case basis.

According to the interpretation of 2010 NTL N10, wells must be designed to contain a blowout. Containment can be achieved in several ways. Working with the BSEE, industry has developed a Wellbore Containment Screening Analysis Tool (WCST) to evaluate the containment capabilities of a given well design. The well can be designed with full pressure integrity such that the well can be shut-in with full column of hydrocarbons (Level 1 WSCT well). The well can also be designed such that, upon shut-in, the primary casing fails but a secondary casing retains the required integrity to contain the flow. With this design an underground flow of hydrocarbons is permitted, but it must be demonstrated that this flow is contained underground and cannot breach to the mudline (Level 2 WCST well). The final option is to "cap and flow" the well. In this case, the well must be designed with sufficient structural capacity to allow containment by flowing back to a surface vessel. This option allows for a lower burst load through the management of flowing wellhead pressure (Level 3 WCST well).

The wellbore system must ultimately maintain its integrity under the collapse loads imparted by an unrestricted blowout to the mudline with no backpressure in the well other than friction generated from flowing through the installed casings, hydrostatic of the seawater column above the subsea wellhead, and the flowing fluid/gas gradient of the blowout zones(s). Drill string, casing failures, formation failures, debris at the wellhead, and other sources of potential back pressure are not considered. Collapsed casing must be assumed to lose pressure integrity and then the prior casing string is subjected to the collapse load. APB loads from the flowing conditions during the blowout must also be considered in the evaluation of casing collapse.

The well must then survive either the burst loading of a shut-in to contain the blowout or the back-pressure from choking the flow in order to capture the produced volumes at surface with one of the industry "cap and flow" systems from MWCC or HWCG. Casing can collapse and fail during the flowing collapse blowout loading as long as the remaining casing(s) and exposed formations (including those behind failed casing(s) will withstand shut-in or a choked flow and surface capture (cap & flow) without hydrocarbons broaching to the seafloor. The well must be choked back enough to capture the entire flow stream at surface with the cap & flow system.

The blowout and cap & flow loads are created by using the best technical estimates for numerous inputs such as pore pressure and reservoir properties with varying degrees of confidence in the inputs. An individual deterministic blowout case is utilized for a scenario better described using probabilistic analysis to determine the potential loading.

The well, as a system, must be designed to address the collapse load associated with unrestricted flow from the reservoir. There are no specific design requirements for any particular casing string (e.g.; the intermediate string, can still be designed with the traditional 50/50 gas/mud gradient for the collapse load). The system must also be designed such that the well will withstand burst pressure of a "cap and flow" load. This load can be modeled for various reservoirs, shoes, and containment systems. Note: BSEE has not permitted wells that feature rupture disks immediately below the base of salt to establish communication with subsalt formation and provide pressure relief after a blowout. However, BSEE has issued permits for wells in which the 11-7/8" liner has been designed to collapse under extreme flow conditions.

Well systems can be augmented with special equipment to enhance containment capability. For example, an external casing packer can be added to a string to contain flow behind a casing and to establish a reliable barrier above collapsed casing.

Regulators require that containment be achieved with a reasonable timeframe. Depending on the reservoir characteristics, pressure depletion may be assumed within that timeframe.

The addition of a well containment design constraint, on top of traditional well design requirements will limit available design options. Deep geologic targets will become more difficult to achieve. Ultra-deep wells are already limited in terms of collapse design and this is challenged further with the blowout loads. Industry recommends that the BSEE consider process safeguards as alternatives to structural solutions on a case-by-case basis for these low probability well control events.

<u>Discussion</u>

New regulations following the Deepwater Horizon incident have resulted in significant changes to deepwater well design, particularly in the design of the intermediate casing. To achieve casing collapse integrity in support of either Level 1 or 2 WCST solutions, heavy-wall 14-inch casing is now commonly run at the bottom of intermediate strings. In some cases, the burst load calculated for the upper section of this string has also required a heavier wall or higher strength casing design. As a result, the landing weight of these long intermediate casing strings can approach 2 million pounds in some applications. These high loads present operational challenges for many deepwater rigs.[5]

The use of a heavier intermediate string creates issues with the load capacities of the rig and casing running tools. Specialty high strength landing strings are available for these applications and buoyancy devices that attach to the landing string have recently been developed to reduce the hook load of the string (note: the advantage of these new buoyancy devices is offset by increased handling risk and more time exposure to heavy pipe across the BOPs during their installation).

In some cases, the running weights may be such that the casing must be set at a shallower depth. In these cases, the casing program is no longer tied to geologic parameters such as pore and fracture pressure, but is dictated by the load capacity of the rig.

Additional strings of casing may be required to reach the well objective as a result of using a shorter intermediate string. The additional casing may be in the form of more, smaller strings, or extended lengths and sections of small OD pipe, or in the form of "scab liners" to cover liner hangers or casing. The requirement for additional casing adds operational risk. This risk will be recognized in running operations, closer-tolerance casing programs, lower safety factors, more under-reaming, more casing points, more tripping operations, having to pump out of the hole to prevent swabbing, more leak paths requiring the use of additional barriers, and increased risk of lost circulation due to higher circulating pressures.

Well design and construction become more difficult, as well, with the creation of additional potential trapped annuli that must be mitigated for APB during the production life of the well.

The containment requirement results in a very conservative design that, over-all, adds risk to the well construction process. It is recommended that this design criterion be reconsidered as a requirement and that other design options be allowed. The load scenario suggested by the containment criterion, while possible, has never been experienced in Gulf of Mexico deepwater drilling, not even in the Macondo incident (note: the partially closed BOP on the Macondo well provided a restriction).

Rather, than simply designing for the extreme case, the designer should demonstrate the conditions under which the well will survive and the probability that these conditions will be reached, as in other high reliability industries. Focus would be directed to the identification of the risk factors and prevention of any loading condition that would prevent an uncontainable well.

In the near-term, more traditional deepwater design criteria, along with the added safeguards and mitigations provided through SEMS compliance, are recommended in lieu of designing for containment. Using well established criteria for lost circulation, kick tolerance, and mud-gas gradients, intermediate casing has been successfully designed, deployed and operated with the required high reliability. For the near-term, it is recommended that historically-accepted criteria be re-established as acceptable design options by the BSEE.

To enhance design capabilities in the longer-term, industry has formed a Blowout Risk Assessment (BORA) JIP. The JIP is charged with developing a risk assessment tool to evaluate the blowout risk associated with well operations (drilling, intervention, and production) in the Gulf of Mexico. Where historical and technical justification can be used as a basis, quantitative risk methods will be utilized in the model. Qualitative risk methods will be used where historical justification is insufficient or where uncertainty is too high. Results will illustrate both the relative uncertainty of outcome as well as the magnitude range of both probability and consequence. Mitigation measures, such as certification, testing and containment capability, affecting both probability and consequence values will be evaluated. A comparative risk assessment (CRA) tool will be developed to help determine acceptable levels of risk.

2) Long String versus Liner and Tieback

FINDING: A long string is a viable alternative to liner and tieback designs. The long string, when properly installed and its barriers properly verified, provides advantages in many deepwater well applications. Both designs have merit and should continue to be available to well designers.[6]

Liners with tiebacks have been suggested or offered to replace some long strings in deepwater wells. This approach has been advanced principally to create additional barriers (a liner hanger packer with cement at the base of the tieback) in the annular leak path to the mudline. However, if a reliable long string annular cement barrier can be established, there are operational and practical advantages to the use of a single string.

One advantage to the use of a long string is the potential to mitigate annular pressure build-up (APB) issues. The lower part of the long string open hole annulus can be cemented and isolated while leaving the annular area below the previous shoe open for APB pressure relief. It should be noted that this mitigation will be compromised if, over time, mud solids settle in the annulus to provide a barrier to the open formations.

While the liner/tieback solution provides additional annular barrier(s), it creates a new concern with the reduced burst and collapse ratings of the polished bore receptacle and tieback stem. This presents an additional leak risk, if not properly implemented. It may require remedial work such as a scab liner or other isolation. This approach necessarily creates an initial trapped annular space that is subject to annular pressure build-up during well construction, well control, and production operations.

3) Production/Drilling Liner – Well Control Design Options

FINDING: For well control scenarios, it is important to retain the design option to allow for production liner collapse. Liner collapse can be an effective way to mitigate flow from the reservoir under extreme well control conditions.

Regulators currently allow the well designer the option to engineer the collapse failure of production liners to address certain well control cases. The designed collapse of a liner can provide a mitigation to flow to surface in extreme well control scenarios. It is important to note that this approach requires that the formation strength and adjacent reservoir characteristics enable the collapsed casing to potentially stop the flow without a breach to the seafloor.

In contrast to this design approach is the desire to preserve liner integrity to support relief well kill operations. A review with the BSEE of these options and the current design requirement is recommended.[7]

4) BOP and Wellhead Equipment for Deeper Water, Higher Reservoir Pressures

FINDING: There are technical, regulatory and operational challenges associated with the use of existing BOP systems in high pressure applications. Without consideration for seawater hydrostatic back-up, current subsea BOP systems are not able to shut-in or cap & flow wells with pressures exceeding 15 K psi at the BOP. Because of the extreme low probability of uncontrolled blowout scenario as a prescribed occurrence, the load case associated with 'cap and flow' well control operations should be permitted for high pressure exploration wells. Operational risk should be considered for management of 'cap and flow' under severe weather conditions such as winter storms and hurricanes.

Currently, industry faces challenges with shut-in and cap and flow wellhead pressures that are predicted to approach or exceed the 15 K psi working pressure ratings of existing 18-3/4" BOP and wellhead systems. In response to this challenge, BOP and wellhead systems are being developed that have 20 K psi pressure ratings. Some components of these systems have been manufactured and qualification testing has been undertaken for casing hanger seal assemblies and surface BOP applications. Additional development, manufacturing, and qualification work will be required before a 20 K psi system is commercially available for subsea application.

At this time, there are no published industry guidelines or standards available for subsea HPHT drilling equipment and well design. Work has, however, been progressed on standards document for 20 K psi applications (the API PER 15 K document is currently under ballot review). For 15 K psi plus drilling, the current direction is the development of custom products with design validation and verifications that are not yet standardized.

5) Annular Pressure Build-up Mitigation

FINDING: Well designers want to retain the ability to choose APB mitigations that address credible risks during well construction and operation. Because of the extreme low probability associated with the uncontrolled blowout scenario load case as prescribed, it is recommended that alternative loads be used to dictate APB mitigations.

Annular pressure build-up (APB) due to changes in the temperature of trapped annular liquid volumes is typically associated with production operations. However, thermal changes can also be experienced in the drilling phase that can lead to high annular pressures in the surrounding casing annuli.[8] In the extreme well control case of an uncontrolled flow from the reservoir, trapped annuli can be exposed to the heat of reservoir fluids for an extended period of time. If these annuli are exposed to such temperature changes, unmitigated pressures can become a problem if they exceed the burst pressure of the outer string or the collapse pressure of the inner string.

A trapped annulus can result from bringing cement above the previous shoe depth, the settling over time of weighting material of the fluid left in the annulus (in an otherwise open annulus), and through the use of a liner and tieback. As examples, depending on well design, a trapped annulus can exist in the tubing annulus, the production casing annulus, and even the 18" x 22" annulus (if cement is brought above the 22" shoe). Frequently, the need to adjust the top of cement to cover stray hydrocarbon stringers (CFR 250.421 (d)) results in a trapped annulus that trades the minimal risk/small volume of the hydrocarbon stringer with the risk of APB during a blow-out or during production of a more significant deeper zone.

Various methods of mitigating excessive annular pressures have been developed. They include the use of specialized (insulating) packer fluids and/or vacuum insulated tubing to reduce heat transfer to the annuli, rupture disks, nitrogen cushions, crushable syntactic foam, and trapped pressure-compensating downhole tools to provide an accommodation space to mitigate pressure build-up.[9] All of these methods have been used to counter APB, however each method has particular operational issues that can influence how drilling operations must be conducted.

Question 2: What are the Operational Challenges with Implementing Reliable Barrier Systems?

1) In-situ Verification of Barrier Integrity

FINDING: Regulations should change to require only one pressure test of a dual barrier system. Additional work should be undertaken to establish standards or to develop and incorporate technologies that improve the interpretation and reliability of "negative pressure tests."

As shown in Figure 1, the verification of a barrier can be accomplished either through pressure testing or through other confirmation processes. Positive pressure testing of downhole barriers is accomplished via an applied surface pressure over the fluid in the wellbore for a specified period of time with the results recorded in either chart or digital format.

Current regulations require that dual barriers (barriers in series) be pressure tested. If the deeper barrier is successfully pressure tested, its integrity will prevent the pressure verification of the upper barrier. Until a suitable methodology is developed to allow a representative pressure test of the second barrier, regulations should be changed to require only a single pressure test of a two barrier system.

There are no accepted industry standards for conducting "negative pressure tests" of downhole barriers, from either procedural or documentation perspectives. The reliability of such "negative tests" should be established. Such procedures and documentation protocols need to be developed in conjunction with the API.[10]

Access limitations prevent the physical testing of some annular barriers. In the case where a pressure test in not possible or practical, the quality of an annular cement barrier must be inferred from various operational indicators or by log evaluation (refer to API RP 96 draft).

2) Reliability of Mechanical Barriers

FINDING: The reliability of a mechanical barrier can be established by various factors including quality in design, manufacture, installation, and testing.

The reliability of mechanical barriers can be established in various ways. Quality in materials, design integrity, manufacturing processes, shop testing, inspection, proper field installation practices, and testing all add to the reliability of a mechanical barrier (refer to API RP 96 draft). Field performance history is also a key indicator of the reliability that can be expected of a barrier.

3) Reliability of Cement Barriers

FINDING: The reliability of an annular cement barrier is strongly influenced by the effective removal of the drilling fluid from the desired zone of cement coverage, water wetting of the casing and formation, and the placement of competent cement to form a hydraulic seal around the entire cross section of the annulus. The ability to achieve a reliable annular cement barrier is in part a function of annular clearance and casing centralization. These two factors are particularly important in the design of cementing programs for tight-clearance casing programs.

It is important to achieve proper centralization of tight-clearance casings to achieve the desired cement barrier performance within the annulus. However, studies indicate that even with good centralization, it may be problematic to place cement in annuli with tight clearances between the hole and the pipe. Hole enlargement practices, regardless of the drilling challenges, are typically employed to achieve improved cement placement.

Other factors influencing mud removal and displacement efficiencies include: spacer and slurry design (volume, density, rheology, and chemical makeup), drilling fluid type and properties, pre-job circulation, and cement displacement rate. Wellbore conditions such as lost circulation and wellbore instability can negatively impact both the final position of the cement, as well as the ability to achieve the proper circulating and displacement rates. In deepwater, narrow mud weight/fracture pressure windows and the higher ECD associated with tight-clearance casing designs impose additional limitations on cementing flow rates. Recommended practices for cementing and zonal isolation are provided in API RP 65 and API STD 65 - Part 2.

While modern ultra-sonic cement evaluation tools are more sophisticated and effective in helping to determine bond quality in tight annuli, the verification of a cement barrier by interpretation of a cement evaluation log, is subjective, and based on inferences from downhole measurements. API 10TR1 provides detailed guidance on cement evaluation practices.

4) Mechanical Lock-Down of Hanger and Hanger Seal Assemblies

FINDING: The requirement to lock down seal assemblies should apply only to those seals with the potential for exposure to hydrocarbons.

Consideration should be given to modifying the regulatory requirement on hanger/seal assembly lockdown to apply only when the potential exists for exposure to hydrocarbon bearing zones. Specific component designs that do not allow seals assemblies to be locked down should be identified. In general, lock-down limitations occur with components that are not exposed to the production interval, but this should be a check point in the well design and permitting process.

5) Casing and Cementing Equipment Reliability

FINDING: There is a need to identify and reduce common casing and cementing equipment failure modes; to increase the reliability of individual components; and to improve the integration of these components so that, once installed, the cemented casing string functions as a highly reliable barrier system.

Examples of common casing and cementing equipment include: the casing/liner itself, casing connections, landing string/running tool, hanger, seal assembly, lockdown sleeve (for casing set in the wellhead), diverter/surge reduction tool, casing shoe, float valve (auto-fill or conventional, single or dual valve), landing collar/float collar, wiper plug (single or dual), launching darts/balls, subsea plug assembly, and the cementing head.

The activation or manipulation of these components is generally accomplished by some combination of fluid circulation, pressure (static or dynamic), pipe rotation, applied weight or tension, and pumping of darts, balls, etc.

The ability of the cemented casing to function as a reliable barrier system is highly dependent on the proper function of each component. If problems are experienced with a particular component, it may not only fail to perform its independent function, but could also negatively impact other components that rely on it for their functionality (i.e. cement quality and placement). Depending on the nature of the failure, the ability to conduct subsequent operations to install/activate other components can be affected (i.e. by not allowing flow, pressure, or activation darts/balls, etc. to reach the proper location).

Examples of common problems are: malfunctioning of the float equipment (not converting from auto-fill mode or not holding differential pressure after the cement job), diverter tools not converting, and wiper plugs/darts not functioning properly – all of which can have significant influence on the ability to place competent cement in the desired location.

Current API recommended practices, such as API RP 10F (Performance Testing of Cementing Float Equipment), require minimal testing and confirmation compared to the loads and demands of deepwater well construction. For example, API RP 10F requires float equipment tests be performed with 12 to 12.5 ppg water base mud, while most deepwater wells use a form of synthetic mud. An update of current recommended practices to better reflect the high demands being placed on barrier equipment is required.

Question 3: What Challenges Exist in Deepwater Completion Designs?

1) Stimulation of Deep Tight Formations

FINDING: The commercial development of deep tight formations will require special production stimulation techniques that may exceed current capabilities.

The deepwater Lower Tertiary reservoir formations have demonstrated low permeabilities that will require stimulation to achieve economic production rates. These deep thick sections will require significant hydraulic energy to achieve the desired stimulation results. Large ID pipe is required to convey stimulation fluids to the formation with sufficient pressure to fracture the formation to access the hydrocarbons. The surface treatment pressures with conventional fracturing fluids approach or exceed the 15,000 psi surface pumping capacity. This limitation can be addressed with heavier fracturing fluids that can reduce surface pressure requirements, but additional work is required to optimize these treatments.

The regulated wellbore containment requirement has potential to impact the size of the liner across the productive interval. If the liner size is too small, stimulation operations will be hindered. As a general rule, in deepwater Gulf of Mexico, 8-1/2” ID pipe across the reservoir is required, with a minimum 9-1/2” ID where safety valves are placed.

Low permeability onshore reservoirs have benefited from the combination of horizontal drilling and fracture stimulation. However, the introduction of these combined technologies in deepwater Lower Tertiary offshore reservoirs will pose greater technical challenges in drilling and completions than those experienced onshore.[11]

2) Well Intervention Systems

FINDING: Intervention operations on deeper and higher-pressure wells may exceed the capacity of available equipment. Additional development of intervention systems will be required.

Well intervention is required for all wells. Deeper and higher pressure wells will exceed the reach of conventional coiled tubing intervention techniques. Approaches such as the use of tapered coiled tubing strings or hydraulic workover techniques can be used to extend conventional intervention limits.

3) Low Cost Reservoir Access

FINDING: While low cost reservoir access techniques have been successfully used in recent years, the development of specialized equipment, systems and deployment vessels will be required to make full use of this approach to access deepwater Gulf of Mexico reserves.

The use of low cost reservoir access (LCRA) techniques is usually considered when smaller accumulations of reserves are in near proximity to existing wellbores. The reserves are typically not large enough to justify the cost of conventional development techniques. LCRA options are enhanced when the original wellbore is designed with consideration for the potential use of these techniques.

Access or intervention approaches might utilize wireline, coiled tubing, or hydraulic workover technologies. Operations could include zonal isolation, recompletion, or sidetracking. The equipment required to provide reserve access will be specific to the well and the operation to be completed. The ability to perform these tasks from MODUs or floating vessels may involve open-water high-pressure risers or high-pressure risers inside drilling risers for enhanced operability and reliability.

Of particular interest, in the area of LCRA, is the ability to sidetrack existing wells to access typically smaller reserve accumulations in deepwater fields. This capability is especially important in fields developed from fixed structures (TLPs and spars). On Direct Vertical Access (DVA) wells the sidetrack is initiated from the existing production casing and production risers. In situations where the projected reserves justify the extra cost, wellbores may be 'deconstructed' by removing existing casing(s) to facilitate sidetracks further up the wellbore. In these types of operations (DVA and subsea), the older wellbores must be evaluated for integrity with respect to containment design from both load and APB perspectives. The wellbore containment criterion may inhibit the use of existing wells, creating the potential loss of reserves.[12]

Some of the challenges associated with LCRA include the availability of tools to perform slim hole (and/or through tubing) sidetracking operations, low-cost operations platforms (MODUs or other vessels), and the development or adaptation of riser systems for subsea applications.

B) Trends and/or Notable Technologies Envisioned for the Near- & Long-term

1) Water Depth

There is an ongoing trend toward operation in deeper water.

2) Well Depth

Well depth has increased with the exploration of the Lower Tertiary formations. This geologic interval exists as a broad band across the deepwater Gulf of Mexico. The increase in well depth creates well design, construction (rig capacity), and operation challenges associated with added depth and higher temperature and pressures.

3) HPHT Reservoirs

Prospects have been identified that will require wellhead systems, well control equipment, and subsea trees with working pressure capacity in excess of 15,000 psi.[13] This equipment is under development and is not expected to be ready for use for a number of years.

4) Intelligent Completions

In an effort to reduce well intervention requirements, many deepwater wells are being constructed with intelligent completions. A high level of equipment and systems reliability is required for this approach to be successful.

5) Wired Drill Pipe

Wired drill pipe technology has matured to the point where it interfaces with all major logging while drilling (LWD) technology providers. Wired drill pipe provides a much higher bandwidth for data transfer than conventional pulsed telemetry techniques. This allows the transfer of continuous high-frequency real-time data from the bottom hole assembly. Benefits have been derived in managing wellbore stability using image logging techniques. Additionally, pressure and temperature measurements, distributed along the drill string, are available to enhance monitoring of hydraulics and hole cleaning. The ability to read downhole temperature and pressure data in real-time, and without circulation, offers significant benefits for data collection and enhanced well control.

6) Managed Pressure Drilling Technologies

A key challenge in deepwater drilling is to optimize the drilling program to reach the target interval with the desired casing size. Several managed pressure drilling technologies are either available or under development at this time for use in subsea applications. These technologies are used to optimize the pressure profile imposed on the open hole. Using these technologies, wellbore pressures are managed in a way that preserves hole size, allowing for longer open hole intervals. Some of these technologies require the use of a high-pressure riser. Others, such as dual gradient drilling, are designed to be used with low pressure riser systems. Several of these technologies have been demonstrated or used commercially in deepwater environments.[14]

7) Pressure and Temperature Measurement Across Barriers

There are several field-proven downhole data measurement and transfer technologies, commonly used in production/reservoir management applications that might be adapted to improve barrier integrity verification, testing, and monitoring in subsea wells, particularly during suspensions and abandonments.
Some of these previous applications include:

- Wired casing & pressure/temperature (P/T) for real-time monitoring of annular P/T during casing, cementing, and production operations (Cooke, SPE 19552)
- Wireless real-time annular P/T monitoring (OTC 12155, OTC 19286, Emerson Article)
- Fiber optic sensor measurements across producing formations (Shell primer reference)
- Surface and downhole micro-deformation sensors for remote measurement of pressure-induced abnormal flows in wells and reservoirs (SPE 138258)
- Memory pressure gauges in liner running tools to compare actual versus simulated liner cementing pressures (SPE/IADC 79906)

Additional applications of these technologies should be investigated to enhance barrier integrity management in all phases of well construction, including drilling, suspension, completion, production, and abandonment (permanent or temporary).
Opportunities exist for equipment suppliers to adapt existing technologies or to develop new measurement and telemetry methods to deliver a suite of fit-for-purpose tools whereby the right data is measured in the right place, captured at the right time, and transferred to surface only for the time period required for the application.
Potential areas for further development in support of subsea applications include:

- Measurement and transmission of pressure data across mechanical wellbore barriers to provide independent positive and/or negative testing of barriers in series

- Wireless transmission of annular pressure and temperature behind casing and liner strings, during various operational phases such as casing installation and cementing, barrier verification testing, etc.

- Advancements in measurement and data telemetry, as well as the integration of sensors, transducers, etc. with existing equipment such as bridge plugs, packers, and various casing/cementing equipment components such as seal assemblies, centralizer subs, and float equipment

8) Other Technologies

Other developing technologies that may be of interest for deepwater applications are:

- Logging While Drilling technology for cement evaluation

- Thermal compensation and computer assisted pressure testing

- APB solutions such as ‘shrinking fluid’ and memory foam

C) Coordination & Communication to Align Industry & Regulatory Efforts

1) Current Alignment Mechanisms

To achieve industry safety and performance objectives, is imperative to establish and maintain an ongoing dialog between operators, equipment and service suppliers, and regulators.

Historically the regulatory agencies have relied upon the technical arm of the API for the development of industry standards and recommended best practices. Many of these documents are cited in the Code of Federal Regulations of Oil and Gas Development. However, the role of

API as both an industry advocate as well as a technical authority has led to confusion relative to these two missions. The recent development of the Center for Offshore safety within the API is a positive development that will help ensure these two roles are separate and distinct both in practice and perception.

a) Offshore Operators Committee (OOC)

The Offshore Operators Committee is the recommended organizational point of contact to provide an ongoing interface between offshore operating companies, suppliers and regulators. It would be beneficial to further develop this relationship to address cultural issues in support of enhanced offshore safety.

b) Petroleum Equipment Suppliers Association (PESA)

The Petroleum Equipment Suppliers Association is the recommended organizational point of contact to provide an ongoing interface between suppliers of offshore oilfield equipment and services and regulators.

2) Improved Relationships

Are there opportunities for improvement in the relationship between operators, drilling contractors, third party suppliers, manufacturers and regulatory bodies?

a) Coordination and collaboration between all parties performing work in deepwater operations is the responsibility of the operator or drilling contractor, depending on contractual relationship. Ultimately, the SEMS process, as implemented by the operator, is intended to provide assurance that all parties are able to work in a well-coordinated fashion and in a safe and environmentally responsible manner.

b) A significant burden has been placed on service companies in preparation to work under the new regulations. As an example, one deepwater service provider has been audited by 23 different companies to assure their compliance with SEMS.

3) Gaps & Issues - Regulations, Standards, Practices, Collaboration, & Technology

a) Regulations - Advanced Notification of Proposed Regulation

Operators encourage regulators to provide advanced notice of proposed regulations. This practice has worked well in the past and afforded operators the opportunity to provide input beneficial to both industry and the regulatory body. This approach would help to identify and resolve potential issues prior to the issuance of regulations.

b) Regulations – Interpretation of API use of "Should" and "Shall"

From the March 28th, 2011 document issued by BOEMRE entitled "Supplemental Information Regarding Approval Requirements for Activities that Involve the Use of a Subsea BOP or a Surface BOP on a Floating Facility," item 1 (b), it is understood that the BSEE has revised their interpretation of API's definitions of the use of "should" and "shall" in those API documents that have been incorporated by reference into the CFR (reference 30 CFR.250.198 (a) (3). It is requested that this new interpretation be officially published in the CFR for use by industry.

c) Regulations – Various Issues[15]

The following regulatory issues were identified as concerns by the authors of this white paper. The authors understand that a process to address issues with regulations already exists in conjunction with the OOC. The following issues have been included in this text as examples only.

i) Requirement to Pull the BOP Stack between Wells

Operational risk in handling the riser and BOP is incurred when pulling the BOP to surface for inspection between wells. Depending on the length of time the BOP has been deployed, operators should be allowed the option of leaving the BOP on bottom when moving between wells.

ii) Regulations - BOP Test Frequency (Workovers and Interventions)

The BOP testing frequency for Completion is 14 days, but the BOP testing frequency for Workovers/Interventions is 7 days. With deepwater subsea well re-entry operations (workover, recompletion, & etc.), risk is introduced by the additional trips required to stay in regulatory compliance. In 2011, it has been possible to obtain an exception (wavier) on workovers to extend the test frequency to 14 days. This was a normal exception (wavier) is the past on subsea deepwater wells. The BOP stack is the same used in drilling & completion which has 14 days.

iii) Regulations - Diverter Activation

Title 30 CFR Part 250.433(b) requires floating drilling operations to actuate the diverter system within seven days after the previous actuation. Historically, if hole conditions were unstable, a departure was requested to extend actuation to the next trip up in to the casing. While routinely granted in the past, more recently this waiver has been denied. If the drill pipe is in open hole, the operator has a choice to pull out of hole to the shoe, or to remain in open hole and risk stuck pipe when function testing the diverter system. Pulling out of the hole increases the risk of a well control situation by swabbing the well. Alternatively, sticking pipe can result in more risk. For example, if the hole packs off, circulation to kill the well will no longer be possible. Denying this waiver creates additional risks to operational safety.

iv) Regulations - Annular and Ram Function Tests

Similarly, Title 30 CFR Part 240.449(h) requires the operator to function test the annular and ram BOPs every 7 days between pressure tests. A departure is typically requested, and granted, to function test the blind shear ram every 14 days, in conjunction with the required 14 day BOP pressure test. However, this waiver is now denied. Tripping out of the hole is one of the highest risk operations on a rig due to the swab pressures induced on open formations. Denying this waiver and requiring the operator to trip out on a weekly basis creates additional risks to operational safety (note: one recent case had an operator pumping out of the hole to function test the rams, a three day exercise, with hydrocarbons exposed in the open hole section).

v) Regulations - Surface ROV Function Tests

A clarification of the regulations is needed with regard to ROV function tests. For example, Title 30 CFR Part 250.449(j) requires the operator to test all ROV intervention functions on the subsea BOP stack during the stump test. The recent interpretation of this requirement includes testing functions that are not critical. An example of a non-critical function is the "All Stabs Retract." This feature protects the rig contractor's equipment, but is not required to disconnect the LMRP.

As the "Rigid Conduit Flush" is also not an emergency BOP function, there should be no reason to require that this feature be tested. Another non-critical function is the "Cut Riser Connector Lock." This ball valve feature offers a way to vent the connector, rather than cutting the line. However, if it failed to work in service, the straightforward contingency is to cut the line. The requirement to test this feature should be waived.

The LMRP Gasket Release function is often disabled on floating rigs. Nonetheless, the current interpretation of the regulation is that it must be tested, even though it is disabled. This interpretation should be revisited for all parties to gain a more clear understanding of the objectives of function testing this equipment.

d) Regulations – Clarification on MASP Calculation

There are multiple references to MASP but little guidance as to what is the minimum acceptable method to be used to calculate same. The wellbore containment screening tool does have some guidance regarding different gas gradient assumptions based on well depth that may be used to determine containment capability, but nothing is stated in the CFR or elsewhere in regulations.

Before the Macondo incident there were many variations of the calculation in use. A clarification of the allowable methods for the calculation of MASP is requested.

e) Regulations – Clarification on Displacement of Wellbore to Lighter Fluids

Rather than requiring BSEE approval, regulators might provide that a negative test be performed prior to displacing and also to require the displacement be performed with a closed BOP if there is only one barrier. It should be made clear that the lighter fluid is a non-kill weight fluid with respect to the pressure or potential pressure beneath or behind a barrier.

f) Collaboration - Demonstration of BOP Shear Capability

As a part of the well permitting process, operators are required to demonstrate the ability to shear any drill pipe used in a well construction project. This must be done with the same type of ram used on the rig. Physical testing may be done under atmospheric conditions, but must be adjusted to ensure shearability under the maximum anticipated wellhead pressure conditions. Shear testing has been undertaken, largely at operator expense, by shear ram manufacturers. Much of the shear data is considered proprietary at this time. Industry would benefit from a cooperative approach to share all available shearing data.

g) Collaboration - The Qualification of Casing and Tubing Connectors

API RP 5C5 provides a process that can be used for proprietary casing connection qualification. The data from the qualification of many proprietary connections have been collected by operators who have funded the testing. An effort has been launched to find the best way to share this qualification testing information between deepwater operators, as these tests are both costly and time consuming.

h) Collaboration – Technology and Safety

Collaboration on technology is usually seen as compromising competitive advantage. However, in areas of well design and execution, technology can provide benefits in safety as well as performance and economics. In those areas where operational safety might be advanced, all should be encouraged to cooperate more fully in order to realize the benefits. Clearly, all parties share the benefit from the reduction of accidents.

i) Standards - Riser and Conductor Fatigue and Failure

With regard to deepwater well integrity, the consideration of riser and conductor system dynamics during drilling and completion is not addressed thoroughly within API. Several issues including fatigue and fracture modes of failure are not substantially covered by API.

j) Collaboration - Well Design

Industry would benefit from a collaborative effort to utilize available formation integrity test (FIT) data (and other relevant information) to develop a salt integrity model which supports 'safe FIT' limits relative to overburden pressure.

D) Human Factors in Safety (e.g. training, procedures)

Industry is discussing ways in which organizations and personnel can develop from a culture of compliance to one of behavioral norms and motivations that focus on structure and control. At this time, a proactive regulator process of grading and counseling is recommended. Such an approach would deliver improved safety results when compared to the historic pass/fail approach to regulatory compliance.

From the Marine Safety Board Advisory Committee: "One of the purposes of SEMS is to make a positive impact on the culture of safety of operators. SEMS elements have been identified as critical to, but not sufficient for, creating a culture of safety. For a culture of safety to exist, there must be a mind set of focusing on safety throughout the organization. The more the operator owns the process, the less the tendency for the operator to equate safety with compliance with prescriptive regulations." – Effectiveness of Safety and Environmental Management Systems for Outer Continental Shelf Oil and Gas Operations (Interim Report 2011).

1) Training and Competency

The casing and cementing design will be reviewed by a Registered Professional Engineer. This is intended by the BSEE as a means to ensure that a competent individual has reviewed and endorsed the casing and cementing program for each deepwater well.

For operational aspects of well construction, personnel training and competency will be performed and assessed according to the guidelines presented in SEMS. Based on 30 CFR 250 personnel are to:

- "… be suitably trained and qualified…" (§250.1909(i))
- "… be knowledgeable and experienced in the work practices necessary to perform their job in a safe and environmentally sound manner…" (§250.1914(b))
- "… possess required knowledge and skills to carry out their duties…" (§250.1915(a))
- "… hold drills … periodically conducted…" (§250.1918(c))

2) Risk Management

Points for discussion include:

- Where are risk assessment techniques currently used? What are the most important areas where risk assessment needs to be advanced?

- Is there a common understanding of the terminology associated with hazard identification, risk assessment, and risk management?

- Are personnel currently trained in risk assessment and management? Do we address "training" or "competence?" What are acceptable sources of such training?
- Are there any perceived gaps or problem areas in the 'reference documents?'
- What are the current mechanisms for aligning the industry and the regulatory agencies?
- Is it possible to establish a framework for a common methodology that can be used to perform a comprehensive risk analysis for well design and construction?
- Are there gaps in regulations, standards, industry practices, collaboration and technologies with regard to risk management?
- What techniques are available to minimize gaps between organizational focus on "personal" safety and "process" safety? How widely are these utilized?

3) Management of Change

The regulation of the management of change process is accomplished through compliance with SEMS. Management of change is a process that is used to identify, control and communicate hazards associated with:

- Design changes,
- Safety critical equipment changes,
- Changes in operating conditions,
- Changes caused by substitution of equipment,
- Changes to written plans,
- Operating procedure changes, and
- Changes to personnel

4) Identification and Management of Critical Elements

Safety-critical equipment is to be designed, fabricated, installed, tested, inspected, monitored, and maintained in a manner consistent with service requirements, manufacturer's recommendations, or industry standards. Procedures must be in place to ensure conformance with specified design and fabrication requirements throughout the life cycle of the project, well or facility.

E) Regulator's Comments

During the development of this white paper the following technical and regulatory comments were received from the BSEE. They are provided here to provide insight to the BSEE position on issues identified within this white paper.

[1] The fracture gradient in salt is determined by adding a pressure value to the overburden curve. There are no identified limits on this practice and operators may be grossly over adding. Different salt types or bodes may determine or limit what pressure additions to make.

[2] Optimal annulus space for possible log evaluation of cement bond quality should also be considered, especially for hydrocarbon zones.

[3] The (***working stress***) design approach is to be expanded to consider the effect on the well's casing and annuli under a worst case scenario, i.e. full wellbore evacuation to reservoir fluid gradient and temperature, in order to access the well's survival and determine how you would need to plan for containment.

[4] These changes may necessitate the need to raise the top of cement for a particular casing which in turn may affect its setting depth and thus the overall design of the well.

[5] Can rigs be reinforced to provide a higher load capacity? This would also allow for some hole sections to be deepened that are limited due to casing weight.

[6] Both long strings and liners with tiebacks are permissible design options.

[7] It may not be favorable to allow production liner collapse if it were to interfere with a relief well intersect and injection into the well or by possibly sending additional debris up hole causing other problems. Overwhelming convincing data should be presented that is specific to the given reservoir for this to be given consideration. With such, approval may not be granted.

[8] This **(*APB mitigation*)** should be approached from the full wellbore evacuation fluid gradient and temperature scenario.

[9] Another method(s) **(*APB mitigation*)** is revising the well design (e.g. if setting a shallow liner, 18- or 16-inch, hung-off in the 22-inch, lower the liner top depth to give less temperature differential increase and thus less fluid expansion). This may also be used in combination with the other techniques. This may require the 22-inch rating to be increased for those joints that would then be exposed.

[10] Should develop criteria for when to perform post cement job evaluation not just for these areas but for any other identified areas of need, such as cement across a hydrocarbon zone or lost circulations zone or base of salt, etc. And what type(s) of evaluation should be performed or considered.

[11] Casing centralization and cementing design would be greatly challenged for deepwater wells. Specific guidance documents would likely be needed.

[12] These wells would be subject (to) the screening process and some may be rejected as candidates, provided containment of a blowout cannot be demonstrated.

[13] What about this relationship with respect to high or extreme temperature as this would affect the BHA, logging tools, completion equipment, any perhaps other well design materials and practices?

[14] MPD that uses surface choke manifold for back pressure to simulate ECD is currently not allowed for subsea BOP's.

[15] Contact with the respective district should be made if such requests need to be made during ongoing operations. This will help keep the district better informed of operations.

Summary of Findings

These are the findings from the white paper development and workshop discussions.

Question 1: Challenges in Casing and Equipment Design for Deepwater Wells?

1. **Well Containment** - The WELL CONTAINMENT design requirement (addressing structural risk), as currently defined by the BSEE, is very conservative from a well control perspective. The requirement, based on a low probability well control event, has led to well designs that add operational risk, limit design options, and exceed operational requirements. Operators believe that the risk of lost containment can best be addressed (avoided) with proactive process safety rather than structural safety measures. It is recommended that alternatives to this design criterion should be considered by the BSEE on a case-by-case basis.

2. **Long String versus Liner and Tieback** – A long string is a viable alternative to liner and tieback designs. The long string provides advantages in many deepwater well applications. Both designs have merit and should continue to be available to well designers.

3. **Production Liner – Well Control Design Options** - For well control scenarios, it is important to retain the design option to allow for production liner collapse. Liner collapse can be an effective way to mitigate flow from the reservoir under extreme well control conditions.

4. **BOP and Wellhead Equipment for Deeper Water, Higher Reservoir Pressures** - There are technical, regulatory and operational challenges associated with the use of existing BOP systems in high pressure applications. Without consideration for seawater hydrostatic back-up, current subsea BOP systems are not able to shut-in on wells with pressures exceeding 15 K psi at the BOP (note: backup pressures, which can be significant in deepwater, are not considered for the BOPs, though they are for casing design – see Question 1, Finding 6). Because of the extreme low probability of WCD occurrence, the load case associated with cap and flow well control operations should be permitted for high pressure exploration wells. Operational risk should be considered for management of cap and flow under severe weather conditions such as winter storms and hurricanes.

5. **Annular Pressure Build-up Mitigation** - Well designers want to retain the ability to choose APB mitigations that address credible risks during well construction and operation. Because of the extreme low probability associated with the uncontrolled blowout scenario load case as prescribed, it is recommended that alternative loads be used to dictate APB mitigations.

6. **Working Pressure Ratings of Subsea BOP Equipment** - The prediction of the benefit derived from hydrostatic pressure back-up is straightforward for simple geometries such as tubulars. The benefit to more complex geometries, such as subsea BOP equipment, is not as easily predicted. Industry should continue to work to estimate the working pressure benefit that can reliably be provided to subsea BOP systems as a result of environmental pressure effects.

Question 2: Operational Challenges with Implementing Reliable Barrier Systems?

1. **In-situ Verification of Barrier Integrity** - Regulations should change to require only one pressure test of a dual barrier system. Additional work should be undertaken to establish standards that improve the reliability of "negative" pressure tests.

2. **Reliability of Mechanical Barriers** - The reliability of a mechanical barrier can be established by various factors including quality in design, manufacture, installation, and testing.

3. **Reliability of Cement Barriers** - The reliability of an annular cement barrier is strongly influenced by the effective removal of the drilling fluid from the desired zone of cement coverage, water wetting of the casing and formation, and the placement of competent cement to form a hydraulic seal around the entire cross section of the annulus. The ability to achieve a reliable annular cement barrier is in part a function of annular clearance and casing centralization. These two factors are particularly important in the design of cementing programs for tight-clearance casing programs.

4. **Mechanical Lock-Down of Hanger and Hanger Seal Assemblies** - The requirement to lock down seal assemblies should apply only to those seals with the potential for exposure to hydrocarbons.

5. **Casing and Cementing Equipment Reliability** - There is a need to identify and reduce common casing and cementing equipment failure modes; to increase the reliability of individual components; and to improve the integration of these components so that, once installed, the cemented casing string functions as a highly reliable barrier system.

Question 3: Challenges in Deepwater Completion Designs?

1) **Stimulation of Deep Tight Formations** - The commercial development of deep tight formations will require special production stimulation techniques that may exceed current capabilities.

2) **Well Intervention Systems** - Intervention operations on deeper and higher-pressure wells may exceed the capacity of available equipment. Additional development of intervention systems will be required.

3) **Low Cost Reservoir Access** - While low cost reservoir access techniques have been successfully used in recent years, the development of specialized equipment, systems and deployment vessels will be required to make full use of this approach to access deepwater Gulf of Mexico reserves.

Reference Documentation

Government Regulations and Notice to Lessees:

- CFR 250 Subpart A thru S
- NTL 2010-N10
- Fact Sheet – On Safety and Environmental Management Systems
- Fact Sheet – An Interim Final Rule to Enhance Safety Measures for Energy Development on the OCS
- DOI Report (May 27, 2010) increased Safety Measures for Energy Development on the OCS

Industry Standards:

- API Bulletin E3 - Environmental Guidance Document: Well Abandonment and Inactive Well Practices for US. Exploration and Production Operations
- API HF1 - Hydraulic Fracturing Operations - Well Construction and Integrity Guidance
- API RP 65 - Cementing Shallow Water Flow Zones in Deepwater Wells, September 2002
- API Std 65 – Part 2 - Isolating Potential Flow Zones During Well Construction - Second Edition (December 2010)
- API RP 90 - Annular Casing Pressure Management for Offshore Wells
- NACE MR0175 - Materials for Use in H2S-Containing Environments in Oil and Gas Production.
- Well Containment Screening Tool
- API TR 5C3 - Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing, and Performance Properties Tables for Casing and Tubing.
- API Spec 5CT - Specification for Casing and Tubing
- API RP 5C5 - Recommended Practice on Procedures for Testing Casing and Tubing Connections.
- API RP 96 - Deepwater Well Design and Construction (publication pending).
- API/IADC Bulletin 97 (Draft) -- Well Construction Interface Document & Guidelines
- API RP 75 – Recommended Practice for Development of a Safety & Environmental Management Program for Offshore Operations & Facilities
- IADC HSE Case Guidelines for Mobile Offshore Drilling Units version 3.3
- ISO 31000:2009 – Risk management: principles and guidelines
- ISO 17776:2000 -- Guidelines on tools and techniques for hazard identification and risk assessment
- ISO Guide 73:2009 -- Risk management - Vocabulary
- ISO 10400:2007 -- Petroleum and natural gas industries - Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing

Downhole Data Measurement References:

- SPE 11416, "Annular Pressure and Temperature Measurements Diagnose Cementing Operations," Cooke, C.E., Kluck, M.P. and Medrano, R.,
- OTC 12155, "Intelligent Running Tool to Provide Real-Time Feedback for Subsea Casing Hanger Landing Operations," T. J. Allen, Cameron, M. T. Worsley, BP Amoco, J. A. Burton, K. W. Elliot, Cameron
- OTC 19286, "Real-Time Casing Annulus Pressure Monitoring in a Subsea HPHT Exploration Well," Sultan, N., Faget, J-B, Fjeldheim, M. and Sinet, J-C, Total Exploration and Production, Norway.
- SPE 19552, "Field Measurement of Strain and Temperature While Running and Cementing Casing," D.R. Morgan, Phillips Petroleum Co.
- SPE 138258, "Advancements in Technology and Process Approach Reduce Cost and Increase Performance of CO2-Flow Monitoring and Remediation," R.E. Sweatman, Halliburton; S.D. Marsic, G.R. McColpin, Pinnacle
- SPE/IADC 79906, "Use of Pressure Gauges in Liner Running Strings during Liner Cementing Operations," J. Brehme, ExxonMobil, A.D. Bain, Weatherford, and A. Valencia, Halliburton.
- Presentation: "Shell's DTS Primer": http://ctemps.org/pdfs/Shell_DTS_Primer.pdf

Editor's Note: The following figures were presented in a 2011 industry forum to demonstrate how regulation changes associated with NTL-10 would be perceived to impact deepwater well design. These figures describe three design load changes that would be required to achieve a wellbore design consistent with the containment requirement. All three of these load changes require that heavier or higher capacity casing be used in deepwater well designs.

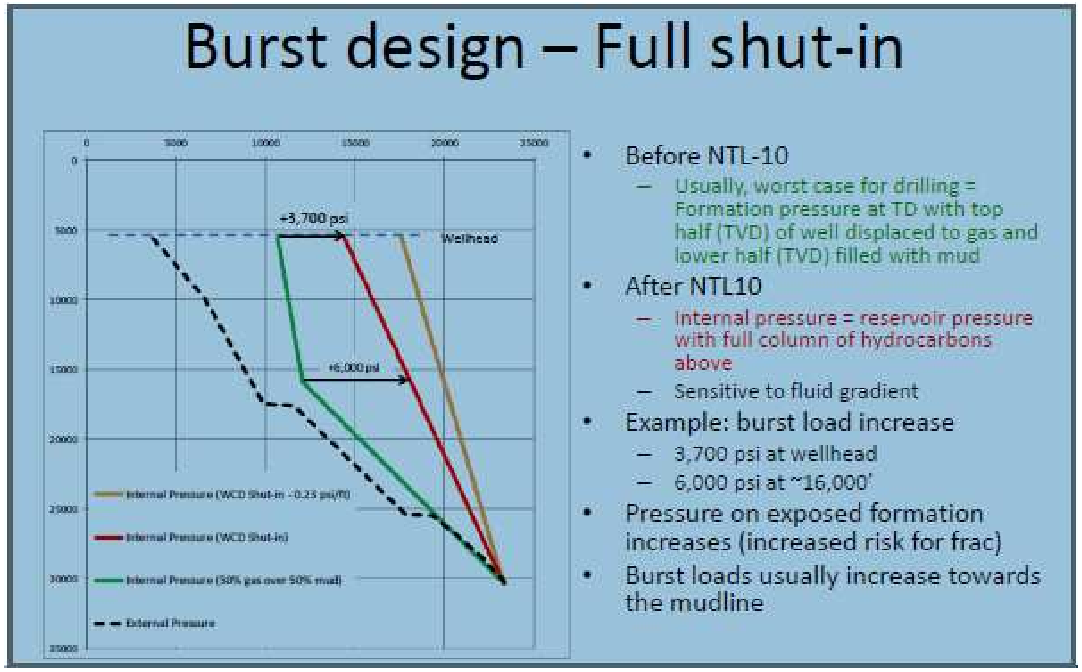

Figure 1 – Burst Design for Shut-in

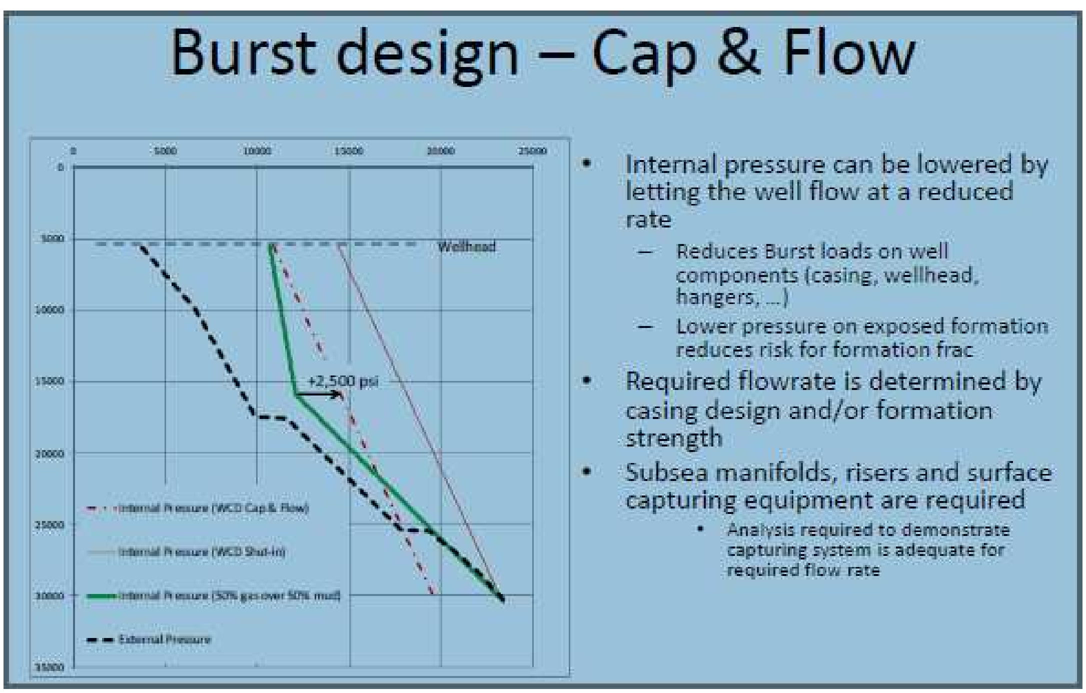

Figure 2 – Burst Design for Cap & Flow

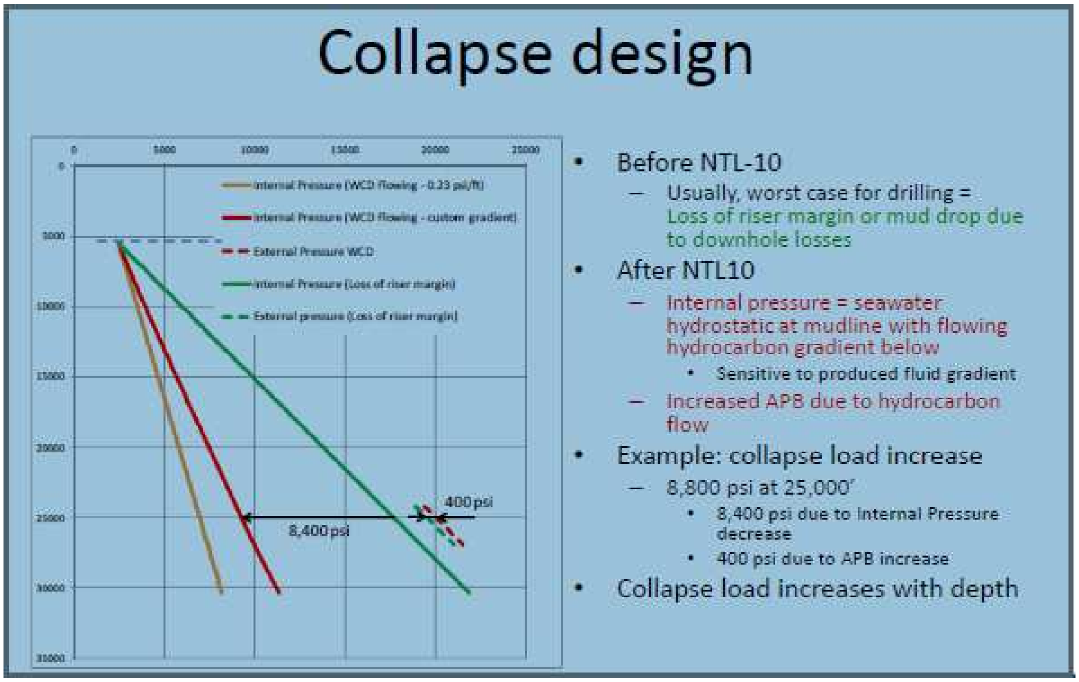

Figure 3 – Collapse Design for Containment

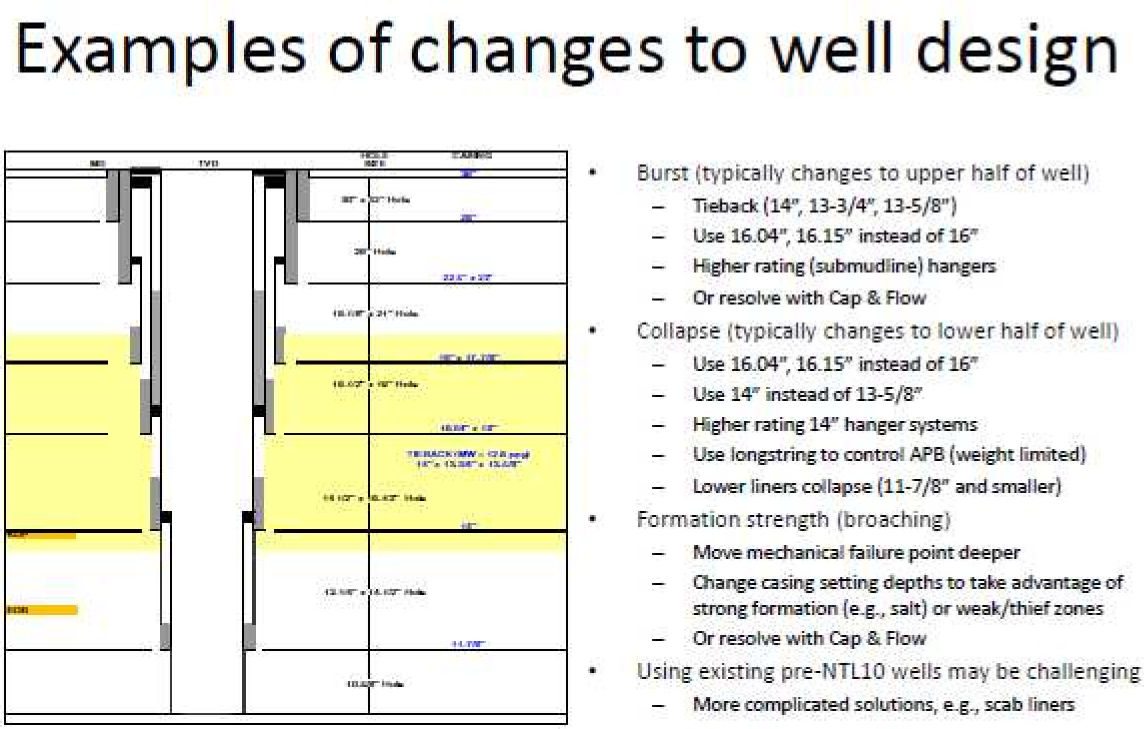

Figure 4 – Well Design Changes

Session 4:
Pre-incident Planning, Preparedness & Response at Different Water Depths

Chair: Alan Summers, Diamond Offshore Drilling, Inc.
Co-Chair: Dan Sadenwater, Chevron

1. White Paper

Effects of Water Depth on Offshore Equipment and Operations
Topic #4: Pre-Incident Planning, Preparedness, and Response

PURPOSE:

This white paper will be used as a starting point for discussions in the breakout session on Pre-Incident Planning, Preparedness, and Response at the Nov 2-3, 2011 BSEE/ANL/Industry workshop on the *Effects of Water Depth on Offshore Equipment and Operations*. It is meant to provide a brief background of the topic and identify current trends and challenges in this area. This paper is intended to address:

- o Current technologies and challenges with implementing those technologies.
- o Trends and/or notable technologies envisioned for the near and long-term
- o Coordination and communication to help align the efforts of industry and regulatory agencies
- o Human Factors in safety (e.g. training and procedures)

SCOPE:

The scope is primarily to identify gaps or challenges in Pre-Incident Planning, Preparedness, and Response at different water depths with specific focus on the barriers that exist above the mudline (Wellhead & BOP for subsea operations and Wellhead, Riser and BOPE for Surface BOPE) that separate the hydrocarbons from the environment.

Below are some focus areas:

- o Gaps in regulations, standards, industry practices, collaboration, and technologies
- o Coordination and communication to help align the efforts of industry and regulatory agencies
- o Human Factors in safety (e.g. training, procedures)

This paper discusses Pre-incident Planning, Preparedness, and Response at different water depths to a major well control event (similar to the Macondo Incident). More specifically the scope includes the wellhead down along with barrier(s) between the hydrocarbons and the environment.

- o Immediate – The first 48 hours post incident, and mainly rig based or close area to the rigs
- o Intermediate Timing – After the first 48 hours post incident, including rig based and beyond. The Intermediate time-frame ends when debris removal begins, the capping stack arrives, or when the flowback system arrives on site.

Effects of Water Depth on Offshore Equipment and Operations
Topic #4: Pre-Incident Planning, Preparedness, and Response

INTRODUCTION / FUNCTIONAL BREAKDOWN

Identify the problem (Onsite Assessment): Broach, Hole in Casing, BOP issues, etc.

Start the planned solution listed in the BOEMRE approve well plan.

Assess the effectiveness – Is it working, or Call the Cavalry?

Equipment on the rig:

- Rig's BOP Systems (Auto Shear, Deadman, Acoustic, Other)
- Storm Plugs on Rig
- Rig's ROV
- Boat based ROV's in field area
- Subsea Accumulator Manifold (SAM)

Equipment in Region:

- MWCC Equipment Setup – Quick Response Equip Only
- Helix Group Equipment Setup – Quick Response Equip Only
- Clean Gulf Setup – Quick Response Equip Only
- USCG Quick Response Assets
- Other Industry Oil Spill Equipment – Quick Response Equip Only
- Oil Spill Dispersants; Subsea and Surface Applications– Quick Response Equip Only

ISSUES

Incident Training: How well trained is the industry, BOEMRE, USCG, and others in a Macondo style incident.

- How can the Industry Train and Drill together to provide the most benefit to a well-coordinated response?
  - Current Training exercises become an INC session; is it possible for a training only session and a 'graded' training exercise with all parties?
  - SC Response Training Requirement for DW IMT by their respective response organization. (HWCG or MWCC)

Effects of Water Depth on Offshore Equipment and Operations
Topic #4: Pre-Incident Planning, Preparedness, and Response

- ❖ Industry needs clear demarcation between source control and oil spill cleanup.
  - ➢ We already have a Source Control IMT specific to containment.
  - ➢ We already have a Spill Response IMT specific to Clean Up.
  - ➢ Regulators should have a clear demarcation between their jurisdiction too to improve and focus oversight during a response.
  - ➢ Jones Act Issues during an emergency

Paramount in this discussion of Pre-Incident Planning, Preparedness, and Response is that human life comes first and the environment second.

REFERENCE DOCUMENTATION

Government Regulations and NTLs:
- o CFR 250
- o Interim Final Rule

Industry Standards:
- o API Specifications
- o API Bulletin 97 (Draft) – Well Construction Interface Document & Guidelines
- o API RP 96 Part I
- o API RP 17H (ROV Interface Specifications)
- o Helix Well Containment Plan
- o MWCC Well Containment Plan

ANALYSIS

Possible directions include thoughts on:

- ❖ The MWCC and the Helix Group capabilities and weakness's? (Education: Industry & Regulators must realize that more capabilities are coming online as time passes)

- ❖ Technical challenges of an oil spill at deep water depths?

- ❖ Vertical Access Limitations based upon VOC?

  - ➢ Why is dispersant approval needed for subsea dispersants if already approved by EPA?
  - ➢ Approved dispersants and dispersal approval process is lacking (few options)
  - ➢ Can the global supply of dispersants be factored in if availability to the US GOM is timely?
  - ➢ Effects on capping stack installation.

- ❖ Technical challenges of a broach at deep water depths?
  - ➢ Does water depth really matter on a broach?

- Shelf may have worse impact due to proximity to shoreline.

- How does one determine competency for well control operations and maintenance of well control equipment?

- What are the current mechanisms for aligning the Industry and the Regulatory Agencies?
  - Jurisdiction?
  - Improved decision making process.
  - Those who drill together will respond mo-better.

- Gaps in regulations, standards, Industry practices, collaboration and technologies.
  - Where is the clear demarcation between USCG and BOEMRE? Is BOEMRE to take on source control and USCG to take on the Oil Spill? We don't need two agencies calling the shots.

- How should a response to Gas with associated condensate differ from an oil response?
  - Liquid hydrocarbon will be significantly less.
  - Based upon Liquid HC, the consequence and response may need to be different.
  - Worst Case Discharge Volumes are not equal to Cap and Flow Capacity – How to educate all on this point

CONCLUSIONS / FINDINGS

- Note areas that could benefit from discussion at the workshop
- Include any preliminary recommendations to BOEMRE, also for workshop discussion

Session 5:
Post-incident Containment and Well Control

Chair: Holly Hopkins, American Petroleum Institute
Co-Chair: Charlie Williams, Shell Energy Resources, Inc.

1. White Paper
2. Workshop Results

Effects of Water Depth on Offshore Equipment and Operations
Topic #5: Post-incident Containment and Well Control

GENERAL PURPOSE

This white paper on "Post-incident Containment and Well Control" is one of six papers that will be used as starting points for discussions in breakout sessions at the November 2-3, 2011 BSEE/ANL/Industry workshop on the *Effects of Water Depth on Offshore Equipment and Operations*. This white paper is meant to provide a brief background of the topic and identify current trends and challenges in this area. This paper addresses:

- o Current technologies and challenges with implementing those technologies.
- o Trends and/or notable technologies envisioned for the near and long-term
- o Coordination and communication to help align the efforts of industry and regulatory agencies
- o Human Factors in safety (e.g. training, procedures)

Note: For the purpose of this document, deepwater well operations will be defined as: *"drilling and/or completion operations that are performed from a floating vessel or structure."*

SCOPE

Topic #5 is substantially about the design, implementation, and deployment of deepwater subsea containment systems. These systems would be deployed on "blowout" wells that are being drilled or completed from floating vessels or a floating production structure (including wells utilizing subsea wellhead/Blowout Preventer (BOP) systems and those wells utilizing surface wellheads/BOPs that are drilled and completed from floating facilities such as spars or TLPs). The subsea containment systems would in all cases be deployed on the seafloor. The systems would be used to achieve one or more of the following:

- Full shut-in and containment of the well via well capping.
- Shut-in of the well with subsurface pressure relief that will not broach the seafloor.
- Containment of the well within a system that allows flow to the surface until a relief well can be drilled.
- Provide for well kill operations such as top kill, bull heading, volumetric kill, and/or secondary intervention by another vessel or rig.

This paper begins with an overview of the causes of a well blowout, typical methods of regaining control, current and near-term challenges, and the new subsea well containment systems. From this foundation, the document identifies and discusses existing technical, operational and regulatory challenges associated with the design, construction, implementation, & deployment of deepwater subsea containment systems and regaining well control. Additionally, consideration is given for the challenges associated with the progression of subsea containment into deeper water depths.

Contents

INTRODUCTION

Primary well control is achieved by a combination of the density of the circulating well fluid system (mud), the mechanical integrity of the well itself (tubulars, cement, and tubular hanging & sealing system), and the integrity of the rock in the open wellbore. The fundamentals of well design to achieve primary well control are the following:

- Predict/determine formation/pore pressure versus well depth and formation fracture resistance/strength versus well depth.
- Determine mud densities necessary to manage the pore pressure versus depth.
- Determine points at which the hydraulic pressure of the required mud density closely approaches the formation fracture resistance.
- Set and cement concentric strings of well tubulars at these points to protect the shallower formations.

During a drilling operation, the well is continuously monitored to ensure the density of the static fluid system delivers a hydraulic pressure that exceeds the pore pressure in the permeable formations penetrated. If the hydraulic pressure is insufficient, the formations penetrated in the open hole may begin to flow into the well (this could be either or both saltwater and hydrocarbons flowing). This event is referred to as a “kick”. A fundamental task in drilling besides maintaining proper mud density is the recognition and early detection of kicks. Although the well is planned for to avoid “kicks”, it is not uncommon, especially in exploration wells for kicks to occur where detailed information about formation pressure is less understood. Kicks can be routinely handled if the kick is detected and dealt with early. They are controlled by shutting in one of the components of the BOP system and circulating out the small inflow in a specifically designed and controlled way while raising the mud weight to eliminate further influxes. Training in these methods is widely required in the industry for well site personnel. A common use of the BOP system is in circulating out kicks – infinitely more common than dealing with a “blowout” situation.

How do blowouts occur?

- Small influxes into the well are not detected, become very large, and cannot be dealt with by normal shut-in and circulation techniques.
- Normal shut-in and circulation fails because of equipment failures.
- Emergency shut-in via the blind shear rams fails for mechanical or other reasons
- Normal or Emergency shut-in by the BOP’s is effective but well blowout downhole in the open-hole section or from casing or shoe failure. This is known as an underground blowout.

BOP devices were first designed to allow shutting in a well that had drilled into and discovered a hydrocarbon zone. In the early days of drilling, the well was simply drilled until it flowed resulting in a "gusher" or what we now call a blowout. Well control and containment procedures and equipment have been in existence for more than a century and have been available and used since the early days of well drilling. The first commercial blowout prevention and well containment equipment were developed and used in the early 1900's. The ram BOP was invented by James Smither Abercrombie and Harry S. Cameron in 1922, and was brought to market in 1924 by Cameron Iron Works.[1]

Modern BOP systems serve many functions and are used in common well drilling operations including:

- Various tests of the well and its mechanical systems
- Shutting in the well on various size tubulars including an open wellbore
- Circulating out and controlling small influxes (kicks)

The industry has extensive and continuing experience using surface BOP's for oil and gas well containment. These can be on the surface of the ground or above the water on a jack-up rig or production & drilling facility. As the industry progressed into deeper water specialized subsea BOP's for the ocean floor were developed. These are the BOP's normally used by floating drilling rigs. This began in the early 1960's. [2] Subsea BOPs are positioned on the seafloor and not on the rig and are connected to the rig via a riser from the subsea BOP to the rig (for most operations). This approach to well control in deepwater fundamentally differs from land or shallow water equipment in that the point of pressure containment (well shut-in) is shifted from the surface at the rig to the seabed where the subsea BOP must be remotely controlled and monitored by a direct hydraulic (relatively shallow water) or electro/hydraulic control system with several layers of redundancy to improve reliability for deeper water. The BOP must be retrieved to the surface for maintenance and repair which is a lengthy activity on a deepwater rig. In some cases remotely operated vehicles (ROV's) are used in positioning and conducting some tests on the subsea BOP. In emergencies these ROV's can monitor and operate the BOP system.

Subsea BOP's have been available for nearly 50 years. The progression of subsea BOPs into ever deeper water has led to a changes and advances. One of these changes includes standardization of subsea wellhead and BOP sizes to An 18 3/4" bore for most subsea well drilling. Standardization always benefits the industry. The subsea BOP is latched to the top of the wellhead housing. There are minor variations in wellhead housing and functionality, but nearly all

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[1] "First Ram-Type Blowout Preventer (Engineering Landmark)". *ASME.org*. http://www.asme.org/Communities/History/Landmarks/First_RamType_Blowout.cfm
[2] "Blowout Preventers – History Performance and Advances". PetroMin July/Aug 2011 (**www.safan.com**)

these utilize a 'stacked' casing hanger design in which the sequential running of smaller, higher pressure rated casings have their casing hanger landed and nested inside the single high pressure (10 or 15ksi rated) wellhead housing. This design of these wellhead systems allows the subsea well to be drilled to total depth (TD) without having to remove or change out the critical well control BOP to accommodate different size or pressure rating casing.

The use of tension loads from the riser of dynamically positioned Mobile Offshore Drilling Units (MODUs) in deepwater combined with increased subsea BOP weight (from increased functionality) have combined to require wellhead housing systems with higher bending load capacity and more structural foundation capacity at the mudline. Anchored MODUs place similar loads on the subsea system but to a lesser extent.

Deepwater subsea BOP stacks have been designed with two connected sections. A lower (BOP) section with a hydraulically operated wellhead connector on the bottom and the assembly that contains the primary well control BOP rams (including blind/shear rams) and the fluid displacement choke/kill valves. Attached above this using and additional hydraulic connector is a Lower Marine Riser Package (LMRP) section which may include annular preventer(s), some of the control system components for the BOP, and the riser flex joint (which allows the rig and drilling riser system to be offset from the well by some angle without damaging the equipment. The flex joint reduces the loads put on the subsea BOP and the wellhead housing and foundation.

As part of modern BOP controls, an automatic and emergency disconnect function is programmed into the BOP control system to allow the well to be secured and drilling riser and LMRP to be disconnected within 45 to 60 seconds of an emergency well control event. This is done through a pre-programmed series of commands that close critical BOP functions and disconnect the LMRP and drilling riser from the subsea well. These systems are known as EDS or Emergency Disconnect Sequence. In the event that EDS operations are impaired or cannot be activated in time, many deepwater BOP stacks are now designed with Auto-shear and Deadman capabilities to activate closure of the primary BOP rams when hydraulic power and electrical signals are cut-off to the BOP. Lastly, intervention panels are provided on the lower BOP section to ensure that remote operation of critical functions can be carried out by ROV's that can be launched & recovered from a multi-purpose construction (ISV/DSV) vessels or other support vessel responding to the offshore incident.

If well control is lost and/or the rig cannot hold station, the blind-shear rams on the BOP can be activated and shut to prevent a blowout as part of the emergency sequence; this requires that the string of drilling pipe in the well be positioned such that the pipe body is opposite the shear rams and that the pipe is centered via use of the annulars and pipe rams. After drill pipe positioning, the blind-shear rams are activated resulting in cutting of the drilling string and full shut-in and closure of the well by the blind part of the blind-shear rams. Following activation of the blind-shear rams and as part of the automatic sequencing noted above, the upper part of the BOP system called the LMRP disconnects releasing the riser and rig from the BOP.

If the blind-shear part of the BOP system fails to activate or close and seal when needed, there is an uncontrolled blowout at the seafloor. In this case, the response is to regain well control via a subsea capping stack with support equipment.

The majority of necessary equipment and techniques to do subsea containment in deepwater has been known to the industry. However, pre-designed, pre-assembled, and tested systems were not available in the industry prior to Macondo. The Macondo MC-252 incident dramatically demonstrated the importance of pre-staging, and pre-planning of this equipment as well as the importance of planning, practice drills, management of change, simultaneous operations management, logistics, and resourcing to address the requirements of a deepwater subsea containment response. The industry did not have equipment ready to cap and flow a deepwater subsea well that was blowing out. There was a demonstrated need to enhance response capability. Now, the industry has equipment resourced and a pre-defined plan in the event of a deepwater well control incident.

This paper addresses the capabilities of the currently available subsea containment systems. It also discussing any technical challenges that such systems might face in the future as well types and water depths change.

ANALYSIS

A) Technologies & Challenges Implementing those Technologies

<u>Current Technology – Marine Well Containment Company</u>

The Marine Well Containment System and Marine Well Containment Company (MWCC) have been established to enhance industry subsea containment capabilities. The MWCC is a not-for-profit; independent organization committed to being continuously ready to respond to a well control incident in the Gulf, and is committed to advancing its capabilities to keep pace with its members' needs. Membership is open to all companies operating in the U.S. Gulf of Mexico. Members have access to the current interim containment system, as well as the expanded system, upon completion of its construction. Non-members will also have access to the systems through a service agreement and per-well fee. Current members include: ExxonMobil, Chevron, ConocoPhillips, Shell, Anadarko, Apache, BHP Billiton, BP, Hess and Statoil.

The containment systems provide pre-engineered, constructed, and tested containment technology and equipment to be mobilized immediately upon being notified of an incident. Preparation and deployment of equipment will begin promptly upon activation of the MWCC team under the direction of the responsible party and Unified Incident Command. It represents an initial commitment of over $1 billion with substantial continuing commitments for operational and technical enhancements and development costs.

The currently available interim containment system consists of equipment owned and maintained by MWCC along with mutual aid vessels. The system meets the Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE) (Now Bureau of Safety Environment and Enforcement, BSEE) requirements for a subsea well containment system that can respond to an underwater well control incident in the U.S. Gulf of Mexico, as outlined in NTL No. 2010-N10.

The interim containment system can handle pressure up to 15,000 pounds per square inch (psi) and is engineered to cap or contain a well in deepwater depths up to 8,000 feet. The capping stack itself can be used to cap a well in up to 10,000 feet of water. The system has capacity to contain up to 60,000 barrels of liquid a day (and handle up to 120 million standard cubic feet per day of gas). It includes the 15 ksi capping stack and dispersant injection system. Through mutual aid provided by members, the interim system includes capture vessels for surface processing and storage.

The centerpiece of the system, the capping stack, is about 30 feet tall, 14 feet wide and weighs 100 tons. The capping stack provides a dual barrier for containment - a blowout preventer ram, plus a containment cap. The subsea valves on the capping stack can be closed to cap the spill, or if necessary, the oil flow can be redirected to surface vessels through flexible pipes and risers.

In the event of an incident MWCC will provide the operator of the well with subsea equipment, including risers, dispersant and hydraulic manifolds, as well as the capping stack. Preparation and deployment of equipment will begin promptly upon activation of the MWCC team under the direction of the Responsible Party and Unified Incident Command. MWCC continues to maintain the list of mutual aid equipment inventory, which will be accessible to the member company in the event of an incident.

The Responsible Party would be responsible for well intervention, relief well drilling, debris removal, and deploying operating equipment. The company is also responsible for securing vessels and surface cleanup. The expanded containment system will have dedicated on-call capture vessels.

While the interim system is available now, an expanded containment system is being engineered and constructed for deepwater depths up to 10,000 feet. It has the capacity to contain up to 100,000 barrels of liquid per day (and handle up to 200 million standard cubic feet per day of gas). The expanded containment system will include a 15 kpsi subsea containment assembly, dedicated capture vessels, and a dispersant injection system.

Contracts are in place and construction is underway on subsea containment assembly, process modules, risers, flow lines and umbilicals. The capability of the interim containment system will continue to build as components of this expanded system are completed and delivered beginning in 2012.

Surface Components
The expanded containment system design includes use of capture vessels (modified Aframax tankers) with up to 700,000 barrels of liquid storage capacity, which can process, via processing modules, store and offload to lighter vessels if the capture vessels are needed.

Modular, adaptable process equipment will be installed on the capture vessels and will connect to the riser assembly that directs the oil from the subsea components. The process equipment will separate the oil from gas, safely store the oil and flare the gas. Then the oil will be offloaded to shuttle tankers which will transport the oil to shore for future processing.
During hurricanes, capture vessels will disconnect and move away from the storm for the safety of the operating personnel, equipment and the environment. Once the storm passes and safety has been ensured, the vessels will return and be reconnected to the free standing risers that remain in place.

Subsea Components
A newly-fabricated subsea containment assembly (SCA) (which is the well cap) will create a permanent connection to the well and seal to prevent oil from escaping into the ocean. The assembly will be equipped with a suite of adapters and connectors to interact with various interface points, including a variety of well designs and equipment used by oil and gas operators in the U.S. Gulf of Mexico. Also, mechanical connectors will be available to connect to pipe if one of the planned connection points is not available.

If the well integrity will allow, the SCA (well cap) will shut in the well and stop the flow of oil, without additional system equipment. If there are well conditions that require that the oil continue to flow, the risers will attach to the SCA and other containment equipment via seafloor flexible flowlines to direct the oil to the capture vessels for storage.

The oil captured by the SCA will flow through flexible pipes to riser assemblies, configured to connect to the capture vessels at the ocean surface. An additional component will be available to inject dispersant into the subsea system during a hurricane when surface vessels must disconnect.

In designing the system, MWCC worked with BOEMRE regulators to ensure all expectations were met. MWCC has continued to stay in regular communication with BOEMRE/BSEE, including onsite reviews and witness testing of the capping stack, as well as a review of the interim containment system equipment. The BOEMRE/BSEE has also participated in a responsible party checklist workshop for new member companies, as well as TLP/SPAR checklist development workshops.

A plan to contain a well under a floating structure, so-called TLP or SPAR, has also been put into place. Capping a well in this case requires a plan to move the structure out of the way to allow access to install the capping stack or a plan to lower the capping stack underneath the structure. All of this activity has been defined and is pre-planned before a well is drilled from a floating structure.

MWCC is committed to continually improve the system to meet future member needs, especially as new technologies emerge.
(Illustrations Attached)

<u>Current Technology – Helix Well Containment Group (HWCG)</u>

Twenty-four deepwater energy companies have joined to form the Helix Well Containment Group (HWCG) to develop a comprehensive and rapid deepwater containment response system. The HWCG has invested in technology & engineering and applied lessons learned from the past, to create a comprehensive well-containment response system made up of equipment, procedures and processes ready to be activated immediately in the event of a subsea well blowout. The HWCG is organized under Clean Gulf Associates, who provides administrative and member services.

Procedures and Processes
The HWCG created a Deepwater Intervention Technical Committee (DITC), comprised of more than 30 technical industry experts, to establish processes and procedures that could be implemented in the event of a deepwater incident. With guidance from BOEMRE the HWCG DITC developed the HWCG Well Containment Plan, a comprehensive and detailed technical plan clearly identifying response protocols for foreseeable deepwater containment scenarios.

Each HWCG member company has committed to a mutual aid agreement, allowing any member to draw upon the collective technical expertise, assets and resources of the group in the event of an incident. Members of the HWCG are conducting a series of crisis exercises and drills to increase coordination and preparedness, striving for continuous improvement.

Equipment
Building upon Helix-owned equipment effectively used in the Macondo response, the system is currently capable of facilitating control and containment of spills in water depths up to 10,000 feet and capture and processing capabilities of 55,000 barrels of oil per day and 95 million cubic feet of gas per day. The HWCG has two capping stacks -- a 15,000 psig capping stack and a 10,000 psig capping stack. The capping stacks are designed to handle deep, higher-pressure wells and would be used in the event a blowout preventer is ineffective. The HWCG has agreements in place with more than 30 service providers who will provide additional services, products and personnel, if needed.

Building upon the foundation of the proven Q4000 intervention vessel, the existing containment system capabilities include:

- The ability to fully operate in up to 10,000 feet of water
- A 15,000 psig capping stack and a 10,000 psig capping stack
- Intervention equipment to cap and contain a well with the mechanical and structural integrity to be shut in
- The ability to capture and process 55,000 barrels of oil per day and 95 million cubic feet of gas per day

(Illustrations Attached)

Explanatory Note – MWCC & Helix
There are many technical and operational differences between the Helix and MWCC systems. However the fundamental differences are flow handling capacity and location of the production risers. The MWCC system uses remote risers while the current Helix system uses a single direct riser vertically above the well.

<u>Current Technology – Other Containment Resources</u>

Many other companies have or are in the process of creating subsea containment capabilities. Most of these are centered on capping stacks. Notable is the Wild Well Control system. These other companies providing discrete subsea containment services do not provide the capability to flow a well to the surface.

Subsea Containment Response Sequence
After a blowout the response sequence for subsea containment is the same for all existing and near term technology. The sequence is:

1- Attempt to intervene and gain well control via the BOP stack using ROV intervention. Gather data with ROVs and other devices and instrumentation.

2- Deploy debris field clean-up resources if there is debris and begin removal. This would include multiple ROV manipulated cutting & handling devices along with ROV hydraulic power units for large scale work. It could also include DW hoisting equipment as well as equipment to straighten a bent wellhead.

3 – Immediately deploy the capping stack, subsea dispersant injection system, methanol injection, and open water capture device. Begin subsea dispersant injection and capture with the open water device.
Note: A special case here is if responding to an event that involves a drilling rig on a floating production structure. In this case there are multiple wells and well risers in close proximity as well as the structure itself potentially blocking capping stack access to the well for intervention. This is a complex scenario that could involve modifying the mooring/tendon system of the structure in order to displace it from over top of the blowing well, which has been developed.

4- Install the capping stack. Provide hydrate mitigation as required.

Several different means exist for transporting and handling the capping stack. These can be limited by the size and weight of the capping stack.

It is important to note that current containment systems are designed to make a hard sealing connect to the well. BOP systems are designed to release the LMRP in an emergency sequence. This is the most desirable connection point for a capping stack. It is thus important for this disconnect to be reliable and effective. Other connection points can include the wellhead housing with the entire BOP removed or at the riser connection point. However simple disconnects at the riser connection point are not currently available. If there is a damaged connector or only a well stub/riser stub, containment projects are developing connectors for this purpose.

Full rated pressure connections are generally available for capping stacks to attach to the LMRP disconnect point. There are some BOP's where the pressure is limited at this point by the fact that one of the two annulars is part of the BOP frame and not part of the LMRP. Since the annular has a lower pressure rating than the BOP rams this reduces the rated pressure at this point. This is not a limit for the capping stack because the body test on the annular is often equivalent to the rated pressure of the capping stack. There is always a fully pressure connection point at the subsea housing. If necessary the full BOP could be removed and the well cap installed at this point. The desired sequence is to attach at the LMRP point first and the wellhead housing second.

In the case of Macondo, the cap was actually attached at the riser stress joint connection. This is the least desirable connection point. First it is usually a flanged and bolted connection and not a hydraulic connector. Second the riser is only is only needed for mud return circulation and has a much lower pressure rating than any of the BOP/LMRP components. However, a connection can be made here with difficulty as noted at Macondo. Also reasonably high pressures can be contained making full use of minimal safety factors and test pressures.

5- Shut the capping stack & shut-in and fully contain the well

If there is minimal debris and there is a clean connect point where the LMRP has released, this is a straight forward operation to install the capping stack. The well is then fully contained and the event is fully controlled. No other containment equipment is required. Achieving this operation successfully is the prime goal of all containment work. If there is another containment event, the likelihood is it can be dealt with in this manner. Thus in many areas now – capping stacks are being made locally available or quickly air transportable as the prime response.

Using the capping stack to gain full shut-in and containment requires that the well have full integrity and can accommodate the pressure from the shut-in. If the well does not have this integrity, a capping stack with a flow system to the surface is required. This lack of full integrity could be a mechanical aspect of the well casing design or it could be due to the fracture pressures of exposed formations in the well. In some special cases, it may be desirable to flow the well with the cap on to mitigate risks from subsurface pressure relief.

6- If the capping stack alone does not achieve the desired shut-in and containment, deploy the flow system.

The flow system involves the manifolds, risers, interconnecting piping, control systems, and surface facilities to flow hydrocarbons to the surface from the capping stack. On the surface the hydrocarbons are captured and the gas is flared and the oil and water are transported to shore by shuttle tankers. Flow would continue until the well was killed and controlled. The well would most likely be ultimately controlled by a relief well. Some operations such as bullhead killing and volumetric kills may be possible at the well itself.

Challenges Implementing Current Technologies

- **What is the impact of water depth on each of the functions or operations?**

The process and equipment components for subsea containment and well capping are the same regardless of water depth in DW. However the capacity and capability of the equipment has to be matched to the water depth. This includes:

- Hydrate prevention is more difficult as water gets deeper and colder. When hydrocarbon gas is being released near the mudline in these conditions hydrate formation is quite likely. Formation and mitigation of hydrates in this environment must be well understood, evaluated and addressed in the design of well control and containment equipment.
- Intervention vessels and equipment must have adequate ratings for the depths being worked. This rating includes the load capacity of equipment at the surface, the length of coil tubing, hoses, umbilicals, tethers, flexible flowlines, etc. and the ability of the equipment on the seafloor to accommodate the increased pressure and current from increased water depth. Equipment is available in ratings to 10,000 feet. It must be simply be qualified and chosen correctly.
- Pressurized hydraulic fluids are often used to provide the motive force for containment equipment. It is more challenging to overcome the effects of the hydrostatic pressure of the DW and to provide a sufficient amount of stored accumulator volume and pressures to quickly activate hydraulic functions in the deep ocean environment, such as BOP rams, subsea tooling packages, debris removal equipment, etc.

It should be noted that capping stacks are available and rated for 10,000 feet of water. The full MWCC expanded system will be capable of working in 10,000 feet of water. The limit of the current MWCC interim system is primarily the risers which are risers extended to their maximum length from Macondo. It is not a technical limitation. The 10,000 foot risers can and will be easily constructed. The maximum depth in the GOM is between 12 and 14,000 feet. Current exploration and production is not occurring in more than 10,000 feet of water. Thus containment system do not have a water depth limitation or technical limitation related to water depth in the GOM.

There are benefits to the water depth in DW which include:

- The increased hydrostatic head of the seawater (approximately 0.45 psi/ft or 1 Atm for every 33' feet of depth) has a positive benefit in that this pressure acts on the well bore and actually reduces the flow rate and maximum flowing potential of a subsea well. It also reduces the differential pressure on pressure containing equipment.
- Although questions remain, dispersants are thought to be more effective in deeper water due to the amount of time mixing and dispersion can occur within the water column.

There are limitations in utilizing DW containment equipment in shallow

water. The challenges in shallow water include:

- The visibility of shallow water well sites may be affected or obscured due to hydrocarbon or gas releases at the mudline.
- Significantly large hydrocarbon releases in shallow water may render direct vertical intervention on the well almost impossible, because of disruption of the water column in the nearby vicinity of the well site and the potential for high concentration of hydrocarbons directly above the well because of the short vertical water path to the sea surface. It is possible to "fly in" capping stacks latterly in this circumstance but that is not the design purpose of current containment systems.
- The 'watch circle' or operating envelope of dynamically positioned vessels will be reduced in swallow water, especially if these vessels are deploying equipment packages that will be connected to the seabed and vessel (such as riser systems) or are required to maintain station keeping for extended periods of time.

Availability of relief wells for floating production systems:

Plans for relief well drilling if required have always been part of an operators planning and portions of this planning are submitted in the permitting process. The information submitted today is more than had previously been required. There are not limitations to drilling relief wells from MODU's in DW. This includes the possibility of drilling a relief well from a MODU to intersect a well drilled from a TLP or Spar that was blowing out. This can readily be done with current directionally drilling and "homing in" in technology. Because of the high rig count in the GOM, availability of MODU rigs for relief well drilling is always assured.

- **What are the most challenging functions and operations?**

The most challenging operation in DW subsea containment response is removal of any debris from the well site. A special case of this is intervention on a drilling well event from a floating production system. This could involve moving the structure in addition to addressing debris. Although debris is not a given in all responses, if it does occur it can be a variety of sizes and weights including the BOP LMRP, a drilling riser, drill pipe, drilling tubulars, or even the entire drilling rig. Much of the debris removal would have to be done with ROVs and crane vessels. Power is limited in deepwater because of the length through which the power (like hydraulics) must be transmitted. Thus hydraulic power units that accumulate power must be deployed on the sea floor. Availability of sufficient DW hydraulic power units must be assured. Lastly this is a non-standard operation that is seldom encountered during normal operations. The volume of ROVs and equipment operating this close together will also result in risk of collision and damage of the recovery equipment itself. This was managed at Macondo but this will always be a key simultaneous operation challenge that can be addressed via good management and planning. Lastly, there could be debris such as a drilling rig that is simply too heavy to be lifted from these depths.

Another challenge in DW containment is conducting the drills, performance tests, and verification tests for containment equipment and system. Such testing if done with full deployment on the seafloor is complex and has some risk of damaging the equipment that you need in a state of readiness. Also deploying a full system may require a large mutual aid effort from several companies, including, in some cases, halting drilling and moving the drilling rig to be part of the response test. How drills are done to be effective but to take into consideration these challenges is important. Subsea production systems are routinely deployed and operated after only performing surface based testing of the systems and hyperbaric testing of some components to prove their capabilities. Containment companies have been formed to ensure continuous readiness to respond. Sufficient drills have been completed to ensure readiness.

An additional major challenge is simultaneous operations (SIMOPS). A subsea containment response requires many vessels in various sizes including shuttle tankers, aircraft, and numerous ROVs. It is a significant challenge to manage all this equipment and its operation. This is further complicated by the small operating area and the risk of collision. There is also the fact that all the SIMOPS have to be done with all equipment in close proximity to volatile hydrocarbons.

There is the impact of adverse weather and its impact on offshore operations. Adverse weather conditions such as strong surface currents in the U.S. Gulf of Mexico (known as ‘loop’ currents) or elevated weather conditions including high wind or sea states and winter storms may hamper or impede the well control and containment operations by impacting the ability of support vessel to carry out routine operations including material handling, crew transfers and crane operations. There is also the risk that all vessels must disconnect and leave for a hurricane, during hurricane season.

There are also minor challenges. The first of these is the lack of training and experience regarding testing and remote intervention on the BOP stack by ROVs. Related to this is the lack of data and instrumentation on current BOPs. This lack of data including condition, well flow-rate, pressures, and ram position makes it difficult to do intervention on a disabled BOP. Lastly, it is the logistics and handling to effectively and quickly deploy capping stacks. Many capping stacks with “flow to the surface” capability are very large and heavy. Some of these cannot be handled or deployed with conventional BOP lifting, handling, and transporting techniques. Containment companies are doing the planning and logistics work to have appropriate lifting, transporting, and handling equipment and techniques available for these large capping stacks. This type of planning and design must continue to be an important part of a containment companies planning and logistics.

There are a number of potential technical challenges and limitations that might manifest themselves in a full subsea containment response that involves flowing to the surface. These have been designed and planned for in the current containment systems. But they need to be carefully monitored in an actual deployment situation. They may result in system limits if they do in fact become problems. One of these is the flaring of large volumes of hydrocarbons. High volume flaring is difficult and the heat loads on the capture vessel would be very large. These systems depend on water spray cooling. Heat loads may have to be managed which would limit well flow rates. If the containment response requires lengthy flowback times with high rates and pressures, this is a significant load on the containment system equipment including chokes, manifolds, flowlines, etc. Since all this equipment is subject to flow erosion, it could limit the system operation. Lastly vessel station-keeping and quick disconnect capabilities during hurricanes and other weather/current events could be limiting. The current plan is for the containment systems to disconnect and leave for hurricanes..

<u>Summary Comments – Mitigators to the Most Challenging Functions & Operations:</u>

- Debris removal operations are made significantly easier if the BOP EDS system has been activated and the Drilling Riser and upper BOP (LMRP) package has been unlocked and released from the subsea well. The timely activation of the EDS system is also necessary to protect the personnel working on the vessel and allows the MODU to disconnect and move (or be towed) away from the well site during the blowout.
- The gaps and deficiencies identified in offshore training, equipment and the performance of subsea tooling packages can be addressed by strengthening expectations and performance requirements in these areas.
- Availability of vessels to transport or perform offshore work should be addressed by the well intervention plans and containment procedures being developed by the offshore Industry.

B) Trends and/or notable technologies envisioned for the near & long-term

Containment equipment must be modified or changed to address generally increasing trend in well pressures and temperatures in DW as they this is anticipated. This will likely include increasing temperature ratings to +/- 350 degrees F and pressure ratings to 20,000 psi and potentially even higher.

Technical advancements that reduce weight, improve ease of handling and installation, and speed of deployment and installation should also be evaluated and considered.

Although it is possible to deploy current subsea capping stacks beneath a Spar or TLP, the capability of the equipment and system needs to be further optimized. In particular, specialized smaller well caps would be beneficial in enhancing install-ability.

The value of a project to develop a hydraulic disconnect at the bottom of the riser and above the LMRP should be evaluated. This rapid release of the riser could be beneficial in some situations. Also such a disconnect could include a high pressure hydraulic connection point thus making the top of the LMRP a more useful connection point for a cap. However, the prime effort should be in ensuring that the LMRP always disconnects with no connector damage.

Lastly, there are projects on better instrumented BOPs, new devices that can supplement the cutting capability of mechanical shear devices, and secondary well shut-in devices that can be pre-run on drilling tubulars. They can be activated if needed to close in the casing deep in the well.

C) Coordination & communication to align the efforts of industry & regulatory agencies

1) Current Alignment Mechanisms

To achieve safety and performance objectives, is imperative to establish and maintain an ongoing dialog between operators, equipment and service suppliers, and regulators.

Historically the regulatory agencies have relied upon the technical arm of the API for development of industry standards and recommended best practices. Many of these documents are cited in the Code of Federal Regulations. The recent development of the Center for Offshore Safety (COS) within the API is a positive development that will help ensure increased safety.

Industry Standards work is a good way to improve relationships. This is a collaborative consensus process. There are many work groups established in API to create and deliver standards. This work is open to all operators, contractors, suppliers, consultants and the government. This working together and opportunity to communicate openly is extremely valuable to deliver quality standards and relationships. The newly established Federal Advisory Committee (Ocean Energy Safety Advisory Committee) also brings together all segments of the industry including the regulators and government to work cooperatively to develop solutions to these challenges. The recently established containment companies and mutual aid resources regarding emergency response are an entirely new and unprecedented forum for cooperation and collaboration. They are also having active dialogues with the regulators. Lastly there are Industry Conferences, Forums and Workshops as well as Industry Trade Associations that have always played a key collaborative role. In particular industry events are opportunities for open communication. Lastly, there are two other organizations to deliver coordination and communication:

a) Offshore Operators Committee (OOC)

The Offshore Operators Committee is the recommended organizational point of contact to provide an ongoing interface between offshore operating companies, suppliers and regulators. It would be beneficial to further develop this relationship to address cultural issues in support of enhanced offshore safety.

b) Petroleum Equipment Suppliers Association (PESA)

The Petroleum Equipment Suppliers Association is the recommended organizational point of contact to provide an ongoing interface between suppliers of offshore oilfield equipment and services and regulators.

2) Improved Relationships

Are there opportunities for improvement in the relationship between operators, drilling contractors, third party suppliers, manufacturers and regulatory bodies?

Coordination and collaboration between all parties performing work in deepwater operations is the responsibility of the operator or drilling contractor, depending on contractual relationship. Ultimately, the safety management system of the operator must provide assurance that all parties are able to work in a well coordinated fashion and in a safe and environmentally responsible manner.

There are other areas for improvement. Perhaps most importantly is enhanced clarity and certainty in the regulatory process including always having appropriate industry comments (e.g. APA process) into the process. A companion to this is simply more and better dialogue and understanding between industry and regulators in general. A good way to create more dialogue is to have increased regulatory participation in the development and review of industry standards. This occurred more in the past but seems to have significantly reduced in the last few years. Another new vehicle for collaboration is the mutual aid resources and well containment organizations striving to be ‘best practice’ industry sharing groups. Lastly there needs to be a functioning Center for Offshore Safety to share safety management system best practices while removing barriers to sharing of industry issues regarding safety.

D) Gaps and Issues - Regulations, Standards, Practices, Collaboration, & Technologies

a) Advanced Notification of Proposed Regulation
Operators would like to encourage regulators to provide advanced notice of proposed regulations. This practice has worked well in the past and provided operators with a chance to provide input beneficial to both themselves and the regulatory body. This approach would help to identify issues to be worked and resolved prior to the issuance of regulations.

b) Use of Dispersant
Industry needs clear and concise regulatory guidance on the use of dispersants during incident response. Dispersants ameliorate volatile organic compounds during incident response and their use allows vessels to operate with reduced volatile organic compounds effects. The Macondo response clearly showed that the use of dispersants enhanced the ability of vessels and crews to operate at site and respond to the incident. Industry should improve the efficiency and effectiveness of dispersants during a response. This work should consider use rates, dispersants specifically formulated for subsea use and enhanced mixing and injection techniques including mechanical devices. The regulatory environment needs to support the use of dispersants in subsea containment responses.

c) Hydrogen Sulfide (H_2S)
Industry should consider the potential issues associated with response to a sour service (H_2S) incident. Plans should be developed for subsea containment intervention for sour service operations in the GoM if any are expected or planned.

d) Well Control Training
There is a need for updated and more advanced well control training (e.g. modern offshore MODU & subsea BOP systems) and more validation of competence for key personnel that operate these systems.

e) Risk based regulation
Analysis of risk and an assessment of where the industry and regulatory focus would best reduce risk and minimize the probability of hydrocarbon release to the environment should guide and prioritize regulation.

f) BOP Control Systems
A review of the MODU BOP and related well control safety systems (e.g. MODU Diverter control systems) should be done. The future state should be the addition of instrumentation and automatic safety systems to BOPs for the assurance of fail-safe operations. This review should include addressing tighter and more specific well suspension requirements and requirements regarding the removal of gas from mud handling systems.

h) Standards
There is currently no regulatory guidance or API or ISO standard for BOP capping stacks. There is no ‘recommended practice’ or API RP on well containment

measures, techniques, and planning. However, task groups have been commissioned to create both documents. Also API should complete and issue new/updated API documents: RP 96, Std 53, Bul 97 which are in process.

i) NTL No. 2010-N10
There needs to be a mechanism to ensure that the growing guidance in support of NTL N10 is based on a collaborative dialogue that ensures that recommendations and decisions are focused on determining and addressing those areas that focus on the significant hazards and deliver best results in hazard mitigation.

j) Containment Company Cooperation
Collaboration between the various companies providing subsea well containment equipment and services should be considered.

k) Hydrate prevention
Hydrate formation made using open water capture devices and capping stacks very difficult. There needs to be new and advanced technology to deliver enhanced hydrate prevention and control.

l) Open Water Capture Devices
Consideration should be given to technical and R&D projects that could lead to technical development and new concepts for open water capture devices. Improvements should include better oil capture rates, internal separation capability, hydrate prevention and resistance, and ease of deployment and operation.

m) Command structure
Improved organizational structures, definition of responsibilities, and incident command functioning for a major subsea containment event should be developed. Current incident command mechanisms did not anticipate subsea containment events and their technical complexity. This improved 'command structure/ infrastructure' should include Government & Industry with pre-defined roles & responsibilities and include enhanced cooperation/collaboration between the USCG and the E&P industry.

- **In which of these areas is the Industry quickly advancing and adapting?**

Industry is moving both collaboratively and rapidly on subsea containment systems and equipment. This quick progress includes the development, availability and construction of BOP 'capping' stacks. Enhanced ROV capabilities generally including new seabed deployed hydraulic accumulator power packs which store additional hydraulic fluid at the seabed to close BOP functions or run specialized ROV tools is also moving quickly. Many more units are already available. There has also been extensive additional testing of subsea accumulators and BOP Control Systems, including remote operation of the EDS. Well designs to allow full cap and shut-in even with annular pressure build-up under worst case discharge (WCD) are being done and the wells constructed. Lastly,

there has been a new spirit of sharing of capabilities & best practices between Operators that has been very effective. An excellent example is the formation of MWCC.
Technology and safety collaboration is usually seen as compromising competitive advantage. However, in areas of safety and subsea containment response technology can provide benefits in safety as well as performance. In those areas where subsea containment might be advanced, all should be encouraged to cooperate more fully in order to realize the benefits. Clearly, all parties share the benefit from the reduction in impacts of an event on the industry and the public.

D) Human Factors in Safety (e.g. training, procedures)

Industry is discussing ways in which organizations and personnel can develop from a culture of compliance to one of behavioral norms and motivations that focus on structure and control. At this time, a proactive regulator process of grading and counseling is recommended. Such an approach would deliver improved safety results when compared to the historic pass/fail approach to regulatory compliance.

From the Transportation Research Board of the National Academies: “One of the purposes of SEMS is to make a positive impact on the culture of safety of operators. SEMS elements have been identified as critical to, but not sufficient for, creating a culture of safety. For a culture of safety to exist, there must be a mind set of focusing on safety throughout the organization. The more the operator owns the process, the less the tendency for the operator to equate safety with compliance with prescriptive regulations.” – Effectiveness of Safety and Environmental Management Systems for Outer Continental Shelf Oil and Gas Operations (Interim Report 2011).

Other ideas to improve training for containment responses include situational training and testing where staff is stressed under realistic situations and realistic situations to behave and make decisions in ways that support system and personnel safety. A potentially good model for this could be drawn from Nuclear Navy. They have had outstanding safety results with the current program even in the face of relatively high turn-over. A clear best practice in SEMS systems is an effective MOC processes with checks and balances. This includes the ‘Stop Work’ processes and protocols which - whenever activity or operation appears to be unsafe – allow anyone to take action to stop the work.

SEMS systems and bridging documents must have clear responsibility and decision making processes based on comprehensive and appropriate expert input. Once the component and tools are established, effective process safety & SEMS programs are based on effective implementation and leadership support. Lastly there needs to be an effective feedback system to guide safety programs that uses the review of major incidents in the OCS and causation factors, including human factor response & decision making that can feedback into improving the system.

- **How are people trained to adequately meet these challenges?**

Containment Companies and Operators participate in table top drills, operational procedure reviews, oil spill and emergency response exercises, well control training classes, etc. Even though Offshore Well Control courses are mandatory for personnel directly involved in, and responsible for, well control and containment operations these courses need to be expanded to give a well systems understanding on how all aspects of the well can potentially impact containment responses. Training and knowledge of the critical MODU and subsea safety systems needs to include non-standard operations such various testing & verification methods and remote (ROV) activation of critical BOP functions. Lastly, 'On the job' training and experience gained from significant hurricane restoration work and response undertaken in the Gulf of Mexico over last 5 or so years has been beneficial as this work has many similarities to subsea containment response.

OTHER FINDINGS & RECOMMENDATIONS:

- **Note areas that could benefit from discussion at the workshop**
    - Adoption of a Risk-based approach to offshore well control
    - Need for additional Industry and Regulator dialogue
    - Additional focus on well control, prevention and training: MODU safety systems, subsea drilling and well integrity, and additional BOP/LMRP testing.
    - The importance of early kick detection in subsea drilling operations
    - Greater awareness and understanding of what to do when a large volume of gas enters the riser, what to do about this, and when it is safe to use the MGS (Mud Gas Separator).

- **Include any preliminary recommendations to BSEE, also for workshop discussion**
    - *Someone who is qualified in well control & well suspension should review the current code requirements and 'Best practices' for proper suspension of a subsea well (including the regulatory requirements for an in-situ barrier philosophy) and the ensuing displacement of any 'temporary barriers' including drilling mud.*
    - *Someone from Wild Well Control or Randy Smith should discuss the need and the methods for early kick detection in offshore wells, and reinforce that <u>preventative action must be taken</u> before significant inflow from an uncontrolled well is allowed past the BOPs and up into the drilling riser.*

Additional Notes and REFERENCE DOCUMENTATION:

i. BOEMRE NTL No. 2010-N10 "Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources"

ii. 30 CFR Part 250 Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Increased Safety Measures for Energy Development on the Outer Continental Shelf; Final Rule

iii. BOEMRE well screening tool

iv. API Recommended Practice (RP) 53 is currently being revised and re-issued as API Standard 53.

v. There are currently no standards or pre-existing documents to define the functionality and the requirements for the dozen or so subsea capping & containment stacks that are currently being manufactured, however, an initiative is underway to provide a 'Industry Standard' to address this gap.

vi. The Bureau of Ocean Energy Management, Regulation and Enforcement – *Report Regarding the Causes of the April 20th, 2010 Macondo Well Blowout.*

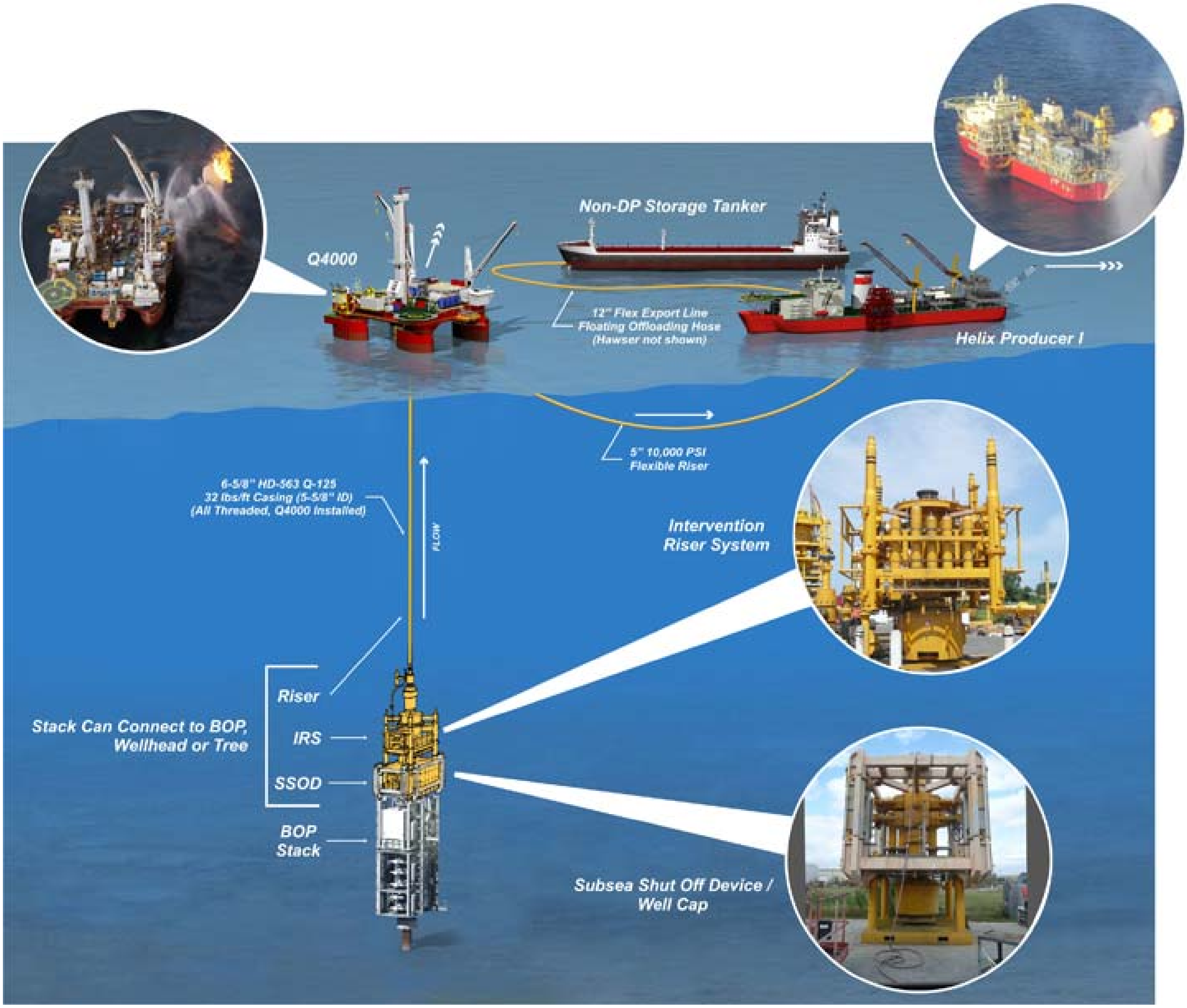
ATTACHMENTS or APPENDICES:

i. HELIX Deepwater Containment System

ii. Marine Well Containment Company System

iii. Joint Industry Task Force Report

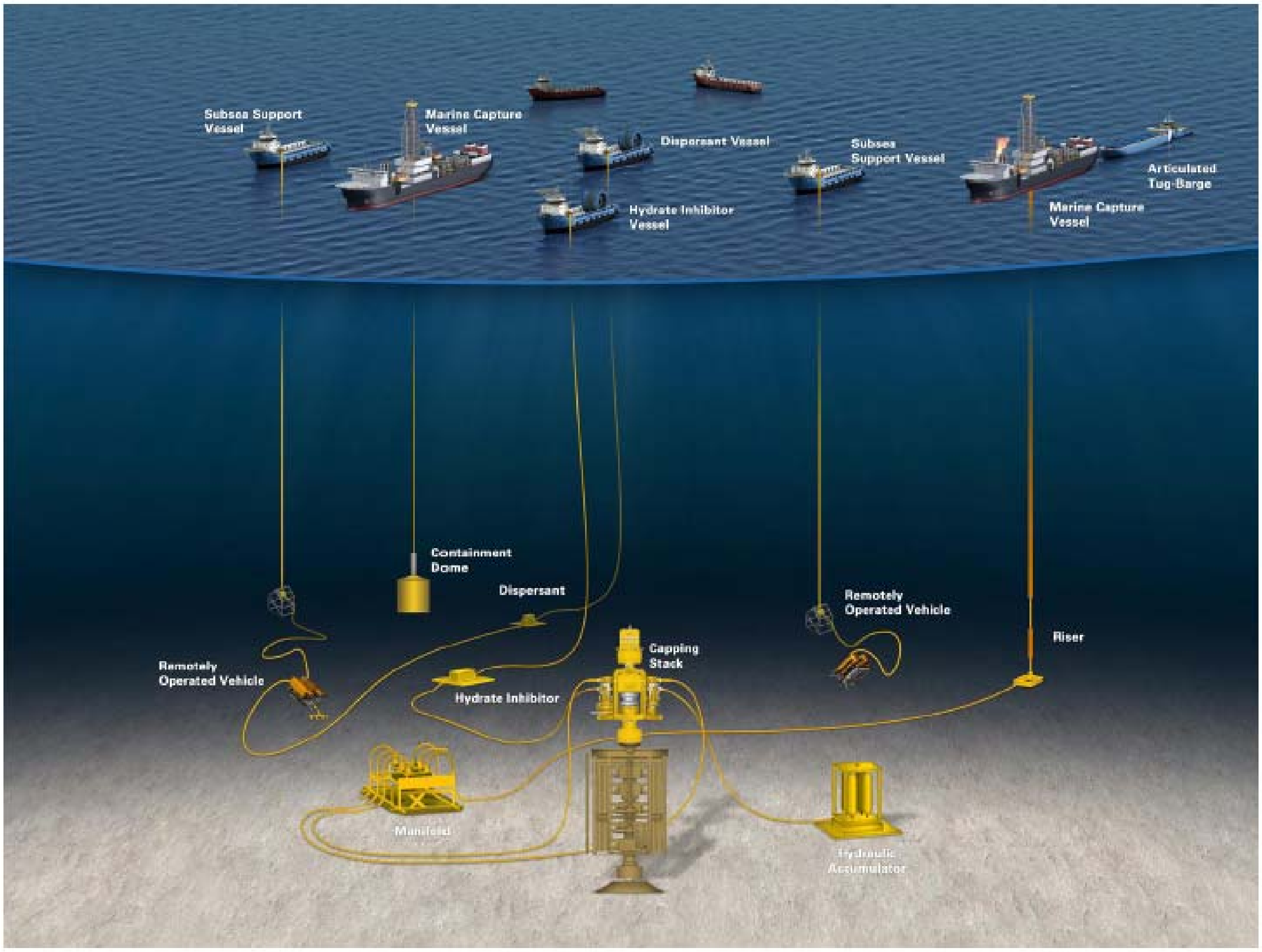
Helix Containment System



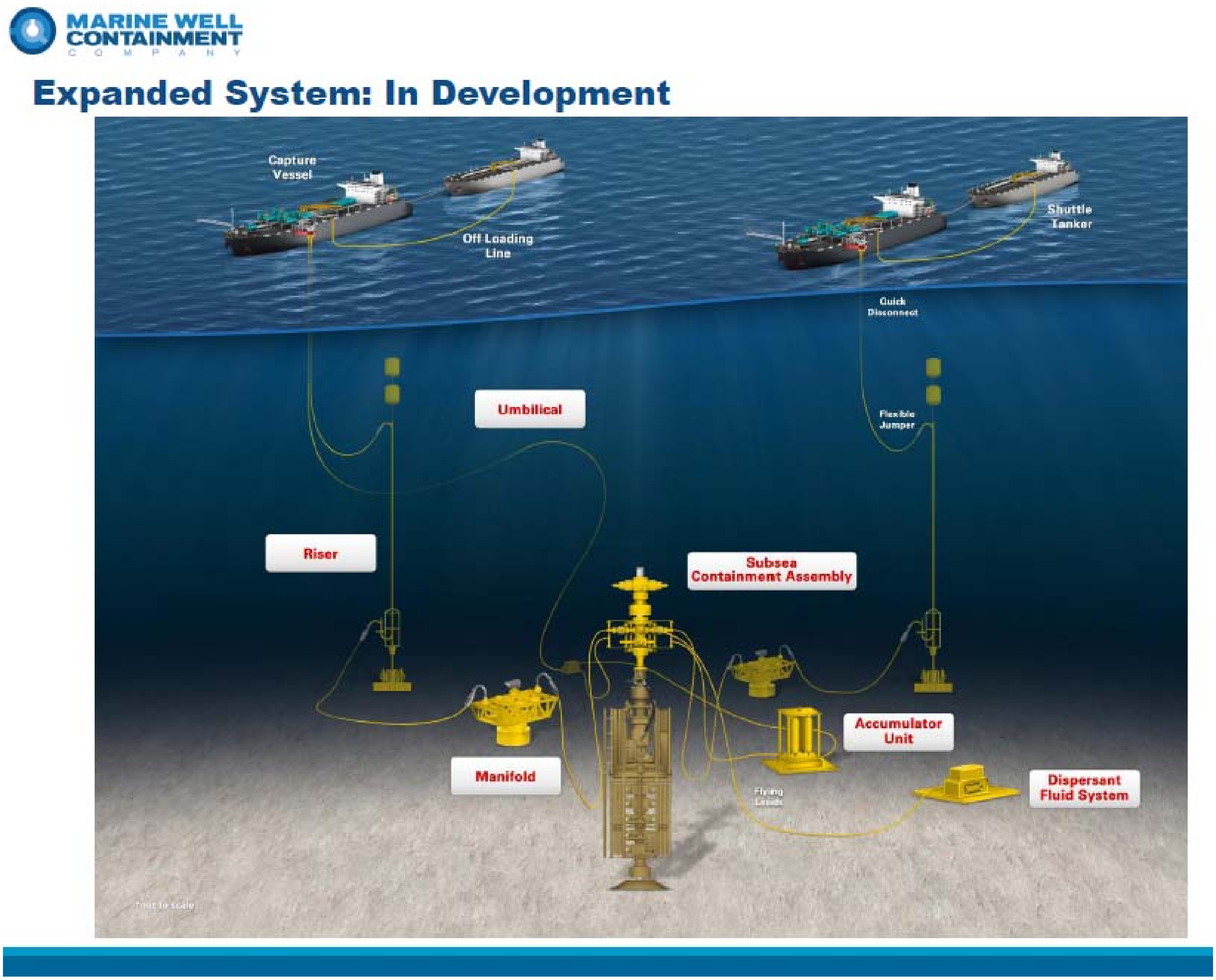
MWCC Interim System

MARINE WELL CONTAINMENT COMPANY

Interim System: Ready To Be Deployed



MWCC Expanded System



JOINT INDUSTRY
SUBSEA WELL CONTROL AND CONTAINMENT
TASK FORCE

DRAFT INDUSTRY RECOMMENDATIONS
SEPTEMBER 3, 2010

Subsea Well Control and Containment Joint Industry Task Force

In response to the Gulf of Mexico (GOM) incident, the oil and natural gas industry, with the assistance of the American Petroleum Institute (API), International Association of Drilling Contractors (IADC), Independent Petroleum Association of America (IPAA), National Ocean Industries Association (NOIA), and the US Oil and Gas Association (USOGA) has assembled a Joint Industry Task Force to Address Subsea Well Control and Containment (Task Force). Overall, the Task Force will review and evaluate current capacities, and develop and implement a strategy to address future needs and requirements in equipment, practices or industry standards to augment oil spill control and containment.

Wherever possible, information developed by the Task Force will be augmented with input from the Regulatory Agencies, oil spill response and well control specialists, investigation panels, and other public sector and other non-governmental organizations. Ultimately, materials produced through this effort will be delivered to Congress, the Administration, and the National Commission on the BP Deepwater Horizon (DH) Oil Spill and Offshore Drilling (Presidential Commission). It is important to note that recommendations will be formulated based on limited information, prior to agency rulemaking, and in advance of any investigative findings in relation to the current incident in the Gulf of Mexico. The contributing joint industry task force companies and trade associations express no views regarding the cause, fault or liability of the incident or regarding any mechanisms of prevention, nor should any recommendations be interpreted as a representation of any such views. The oil and natural gas industry remains committed to working with Congress, the Administration, the Regulatory Agencies, the Presidential Commission, and interested stakeholders as we work to enhance and augment oil spill control and containment.

Schedule and Work Plans

Short-term (Completed Tuesday, July 6)

- Review existing efforts and identify opportunities for augmenting capability, including examination of possible pre-staging of equipment, and research & development in the follow subcategories:
    1. Well Containment at the Seafloor
    2. Intervention and Containment Within the Subsea Well
    3. Subsea Collection and Surface Processing and Storage
- Review industry data associated with operation and testing of subsea well control and response methods, with the objective of identifying issues, areas of concern, etc.
- Identify potential for enhancing capability.
- Develop a strategy and action plan to complete Mid Term commitments.
- Develop subgroups to focus on specific issues.
- Communicate initial findings.

Mid Term (Completed September 3, 2010)

- Review existing testing and inspection requirements, regulations, protocols for subsea well control and containment. Based on industry experience, incident data, overlaying current regulations and requirements, etc., make recommendations to Presidential Commission and other appropriate government entities that can enhance subsea well control and response.
- Review Section II. C. (Wild-Well Intervention, Recommendations 9 & 10) of the DOI May 27 Safety Report, make recommendations regarding implementation of this section, including possible volunteers to the technical workgroup.

- Confirm current capability within the industry, including capability used successfully for containing the Macondo well.
- Make immediate recommendations that make available near term subsea containment solutions in support of enabling the resumption of industry drilling operations.
- Make long term recommendations on subsea containment solutions.

Long Term (by December 31, 2010)

- Develop a strategy and action plan to complete Long Term commitments.
- Review information available from recent Deepwater Horizon incident, specifically associated with subsea well control and response. (Junk Shot, LMRP Cap, Top Kill, etc.)
- Provide detailed report on progress and activities of the Task Force.
- Identify next steps/milestones to enhance subsea well control and containment capability.

Task Force Participants

AMPOL, Apache, API, Anadarko, ATP, Baker Hughes, BHP Billiton Petroleum, Chevron, Cobalt, ConocoPhillips, Delmar Systems, Diamond Offshore Drilling, Dorado Deep, ENI, ExxonMobil, FMC Technologies, GE Oil and Gas, Halliburton, Helix, IPAA, McMoRan Exploration, Newfield, NOV, Petrobras, Schlumberger, Shell, Statoil, USOGA, Wild Well Control

Executive Summary

The Joint Industry Task Force was formed to review current subsea well control preparedness and response options to determine their efficacy throughout all offshore operations. The review includes equipment designs, testing protocols, R&D, regulations, and documentation to determine if enhancements are needed. The Task Force will identify actions necessary to move standards to advance industry performance and identify enhancements. Where appropriate, enhanced capabilities and other information developed from the DH incident will be considered.

This task force will review intervention and containment at the seafloor along with processes for conveyance and processing to the ocean surface. The primary focus will be on single wells in deepwater and on operations that can occur after a BOP has failed and ROV shut-in attempts have failed or are not possible. The primary objective of subsea containment is to minimize the total time and volume of hydrocarbons discharged to the environment. Each incident needs to be assessed and the best available response and containment measures employed. Consideration will also be given to containment of open casing or casing leaks. Although some technical solutions can be applied to subsea producing wells and templates, these will be focused on in future work. The review will not include Blow Out Preventers (BOPs) and control systems such as Emergency Disconnect Systems (EDS), Autoshear Systems, and Deadman Systems all of which are covered in the Offshore Equipment task force. The task force will focus on well control and containment procedures including well shut in, kill methods, subsea capping, and collection & processing methods.

This task force has initially identified 5 key areas of focus for Gulf of Mexico deepwater operations, the Focus Areas: well containment at the seafloor; intervention and containment within the subsea well; subsea collection and surface processing and storage; continuing R&D; and relief wells, developed by the Task Force respond to the recommendations published by the Department of Interior on May 27, 2010 (no.s 9 and 10 respectively, excerpted and included as Appendix 1 in this document).

We make 29 specific recommendations within these areas of focus. Fifteen of these recommendations are for immediate action and we recommend begin immediately and plan to facilitate. Others will take a longer time and are focused on research and developing capability.

One of the most important "Immediate Action' items is to provide near term response capability until longer term projects and capability are available.

The near term capability must be made available to the industry via a collaborative Containment Company (like MWCC, Marine Well Containment Company). This can be accomplished via four action items: inventory equipment and capability that has been proven fit for purpose through use in response to the Macondo blowout and acquire all appropriate equipment into a Containment Company; reviewing the services and contractors that are advertising immediate containment capability and contract those best able to deliver near term response to the Containment Company; review available equipment for containment that is available "off the shelf" from manufacturers and acquire appropriate equipment; and review vessels and vessel contracts from the Macondo response and contract for those vessels necessary to provide near term containment response. Discussions and negotiations are already under-way to make the BP owned containment equipment available via a Containment Company.

Well Containment and the Sea Floor

Our first set of recommendations are to address the goal of establishing a framework and capability for joint participation and cooperation in the industry in the area of subsea well control. We have the opportunity to enhance our capabilities through the acquisition of the equipment and technologies used in response to the Macondo event. Our immediate recommendations are to make the equipment and technologies used for the Macondo well available to all of industry through a Containment Company, and to make use of best practices and learnings from the Macondo response. The Containment Company will also do research into improved methods and equipment for subsea well control and containment. The Company will improve on designs used for Macondo and then procure, construct and test the needed equipment including over time drills, exercises and readiness reviews.

Our next recommendations involve industry improvements and research regarding the lower marine riser package (LMRP) release. We specifically recommend ensuring the LMRP can be removed from the lower BOP using a surface intervention vessel and ROV to get access to the connection mandrel on top of the BOP. In the future we recommend further LMRP development: developing a method to release the LMRP without riser tension; developing methods for high angle LMRP release without damage and high angle reconnects; and developing a new quick release for risers at or above the flex joint.

Additionally in the well containment and the sea floor focus area, we recommend the ability for a vessel to remove a damaged or non-functioning BOP stack to allow installation of a new BOP on the wellhead housing or the subsea containment assembly, and second, be able to repair or replace a non-functioning control pod to be able to regain full functionality of the BOP stack.

We also recommend that there be an assured ability to connect the subsea containment assembly and other response equipment to all flanges and connecter profiles used in the industry. We recommend that the Containment Company acquire and maintain a full set of equipment and design and construct subsea connectors. We also recommend developing more effective methods of connecting to and controlling BOPs with ROVs.

Intervention and Containment within the Subsea Well

This section recommends that industry begin researching and developing capability in wellhead structural support, subsea stripping and snubbing technology, subsea coiled tubing, subsea freeze plug techniques and improvement and enhancement of Top Kill Methods.

This task force will work with the API RP 96 Deepwater Well Design workgroup to review well designs and assure designs that provide for full shut-in with containment devices.

Subsea Collection and Surface Processing and Storage
This set of recommendations is focused on having the Containment Company immediately develop the means to rapidly deploy production and processing equipment that will interface with containment equipment to convey wellbore fluids to surface for flare and transport. Further, this section makes recommendations specific to the Containment Company development of the capability to make a full containment connection to the seafloor that can be installed over the BOPs or a casing stub.

Continuing Research & Development
These recommendations focus on industry developing capability so that we can extend containment concepts to Subsea Producing Operations and putting a focus on researching new technology for subsea containment. We also recommend publishing the findings from the Task Force work as an educational background for the public, regulators, legislators and other stakeholders.

Relief Wells
We recommend for immediate action holding focused workshops to determine the most effective methods and information that should be included in well plans regarding relief well drilling planning. We also recommend reviewing technologies for relief wells –immediately by reviewing already published work - and in the future working with experts and vendors of specialized equipment that could potentially improve relief well capability.

Conclusion
This report is the reflection of the Task Force's identification of industry's current capability – including the capability used for containing the Macondo well – and the identification of longer term recommendations to enhance subsea well control and containment.

Focus Area	Description	Summary of Recommendations
Well Containment at the Seafloor	Establish framework and capability for joint participation and cooperation in the industry in the area of subsea well control and containment.	1. **Immediate Action:** Establish coordinated industry capability for owning and providing subsea well containment technology and capability. Immediate containment capability will exist via acquiring and refurbishing capability used by BP, contracting GOM contractors with immediate existing containment capability, and acquiring containment equipment available off the shelf from suppliers. This immediate containment capability will be provided via a Containment Company. 2. Near Term Action: Establish long term coordinated industry capability for owning and providing subsea well containment technology and capability. This recommendation and action can be addressed by the Marine Well Containment Company (MWCC) This will be a non-profit Company open to all industry with capability which will include the MWCS (Marine Well Containment System) constructed by the four company consortium. Or by other Containment Companies with suitable capabilities and support that are established in the GOM. All Containment Companies and systems will make use of best practices and learnings from the Macondo response. 3. Well Containment Systems should deliver a flexible, adaptable, and rapidly deployable tool kit of containment equipment. The equipment should be purpose designed and constructed for rapid deployment and successful subsea containment. It should fully contain the oil by full mechanical connection to the well or to the sea floor. The Containment Company should procure, construct, and test the needed equipment. This includes testing effectiveness over time through drills and readiness reviews. The Containment Company should also do research into enhanced methods and equipment for subsea well control and containment. The MWCS will become part of the non-profit MWCC which will be open to all industry. It will be managed via boards similar to existing spill non-profits. It will issue reports appropriate to its mission.

Focus Area	Description	Summary of Recommendations
	Remove LMRP in the event it is not released as part of the emergency disconnect sequence. Be able to use ROV and surface intervention vessel to unlatch and remove LMRP to get access to the connection mandrel on top of the lowermost BOP.	4. **Immediate Action:** Confirm LMRP can be removed from lower BOP using a surface intervention vessel and ROV. This should allow access to the mandrel on top of the BOP and the installation of subsea containment assembly. This assembly should have full shut-in capability in addition to choked flow from flow arms. If well flow is necessary it can be achieved by diverting flow to the capture vessels. The subsea containment assembly also allows vertical access to the well for intervention within the well if necessary. In almost all cases where there is confidence in the integrity of the well design, the well can be shut-in and top kill procedures executed. Well "capping" capability is available now through use of a second BOP stack or equipment used in the Macondo incident. Containment Companies should expand this capability.
	Develop new methods to release LMRP without riser tension.	5. **Immediate Action:** Ensure effective methods to release LMRP‟s are included in BOP stack designs. This should include releases with no vertical tension is available as when rig is drifting without power. Releases should not damage the BOP or BOP connections. There are tools and techniques available now such as LMRP jacks but new methods should be considered.
	Develop methods for high angle LMRP release without damage and also high angle reconnects.	6. Research & Develop Capability – Ensure effective and non-damaging release of LMRP‟s. High angle release connectors exist now. This recommendation is to ensure they work in non-riser tension situations and that there is no need for additional development. Review connectors and develop new capability if necessary to reconnect to BOP‟s and wellhead housings when they are non-vertical.
	Develop new quick release for risers at or above the flex joint/stress joint	7. Research & Develop Capability – Develop new quick release that can be installed in the lower riser sections to enable quick release and reconnect when the LMRP does not release in the emergency sequence.
	Remove damaged or non-functioning BOP stack. Be able to use ROV and surface intervention vessel to unlatch and remove BOP stack to get access to a subsea wellhead	8. **Immediate Action:** Remove damaged BOP stack to allow installation of a new BOP on the wellhead housing, or the subsea containment assembly. With a good integrity well design the well can be shut-in and normal kill procedures can be used. This capability is available now through use of a second BOP or equipment used in the Macondo incident. The Containment Company should expand this capability.

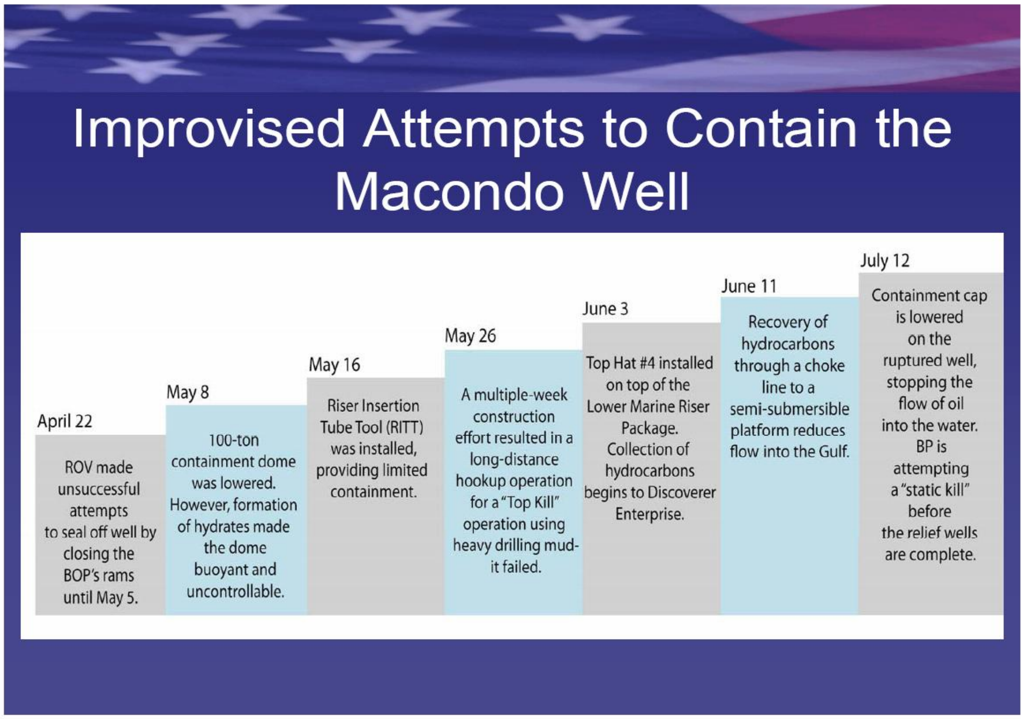
Focus Area	Description	Summary of Recommendations
	Regain full control of BOP stack. Be able to repair or replace non-functioning control pods to be able to regain full functionality of BOP stack (ROV intervention provides limited functionality)	9. **Immediate Action:** This can be done now with some hydraulically controlled stacks and on all rigs by pulling and repairing the LMRP/pods, and rerunning the LMRP. - Research & Develop Capability: Research & develop ways to regain control over all important BOP functions in the case where the LMRP is damaged and cannot be removed and in cases where the LMRP is removed but cannot be repaired and re-run. This would be for cases where adequate control cannot be established with ROV intervention.
	Provide additional and more effective methods of connecting to and controlling BOP‟s with ROV‟s.	10. **Immediate Action:** The Containment Company should acquire and maintain a full set of crossover spools, connectors, and hub combinations. 11. **Immediate Action:** The Containment Company should design and construct subsea connectors to fully seal, connect and contain on damaged connector profiles and casing stubs. Also consideration should be given to inside well connectors such as packers. 12. **Immediate Action:** Coordinate with the Equipment Task Force to ensure methods and equipment are providing effectiveness and reliability in delivery of control fluids and control to BOP‟s and ROV‟s. Considerations should include: - Evaluation of methods other than shuttle valves, for the ROV intervention plumbing. 13. Research & Develop Capability – Review existing methods and number of connection points on existing BOP‟s. Determine if more outlets or different connections would enhance containment capability.
	Deepwater cutting, metal, and debris removal	14. Research & Develop Capability - Assess industry capability and conduct in-situ testing to determine what new technology and capability needs to be developed to remove a debris field and cut equipment like risers. Develop new equipment and capability as determined by testing.

Focus Area	Description	Summary of Recommendations
Intervention and Containment within the Subsea Well	Assure necessary wellhead structural support via design & practices in the event of strong side forces from drifting connected rigs and riser collapse from rig sinking.	15. **Immediate Action:** Coordinate with API RP 96 and ensure deepwater well design includes a system evaluation of the design and material for subsea well head support (e.g.: templates, structural pipe etc.), and the release control methodology of the LMRP.
	Subsea Stripping and Snubbing Technology to allow intervention inside damaged wells	16. Research & Develop Capability - Survey industry for feasibility of developing subsea snubbing technology or consider proposal to Joint Industry Groups (RPSEA/Deepstar etc.) to develop preliminary designs for subsea snubbing equipment.
	Subsea Coiled tubing to allow intervention inside damaged wells	17. Research & Develop Capability - Seek opportunities to accelerate development of subsea coil tubing deployment systems and make them available for subsea well intervention on damaged wells and BOP‟s. Consider all possibilities such as deepwater pipe-lay technologies for deploying pipe larger than conventional coil tubing.
	Subsea freeze plug techniques for subsea well containment	18. Research & Develop Capability - Survey industry experience, conduct research into basic science if necessary, and undertake field testing to develop industry capability for establishing and maintaining an „ice plug‟, to provide subsea well containment while avoiding detrimental affects to the BOP operation.
	Improvement & Enhancement of Top Kill Methods including evaluation of Reactant Pills and other Bridging Agents for subsea wells	19. Research & Develop Capability - The top kill method should be considered when the subsea well is contained by the subsea containment assembly or the BOP. This requires well integrity and containment integrity sufficient for the top kill. This effort should include a survey of capability, and development of supporting technologies for converting fluids into barriers in situ, augmenting bridging if desired, and pumping procedures and planning including hydrate management.
	Review well design criteria of RP 96	20. **Immediate Action:** The Task Force will coordinate with API RP 96 Deepwater Well Design team to ensure they understand the importance of full shut-in capability to the containment capabilities.

Focus Area	Description	Summary of Recommendations
Subsea Collection and Surface Processing and Storage	Develop means to rapidly deploy production and processing equipment that will effectively interface with containment equipment to convey wellbore fluids to surface for flare and transport.	21. **Immediate Action**: The Containment Company will deliver a modular solution for capturing, processing, and transporting production from subsea wells that need to be produced until well control is complete. Such a system should be adaptable to DW metocean and water depths up to 10,000 feet. It should consider free standing production risers to move production to the surface away from the area of the well. It should have processing capability that can be rapidly deployed on vessels. All the equipment should be purpose designed, pre-constructed, and held on ready stand-by. Any concepts forwarded through BOEMRE Alternative Response Technologies Program should be evaluated and researched and included if they enhance capability.
	Develop capability to make a full containment connection to the seafloor that can be installed over the BOP‟s or a casing stub.	22. Research and Develop Capability – The Containment Company will develop, test, and have available technology to provide full containment via seafloor connection. This system should allow connection of a Subsea Containment Assembly so well production can flow to the production and processing system. Such systems should include chemical injection for hydrate mitigation. The sea floor connected containment system would be used for oil capture until a relief well was drilled.
Continuing R&D	Extend containment concepts to Subsea Producing Operations and equipment	23. Research & Develop Capability – As the next phase of the Task Force, evaluate extension of containment concepts, equipment, and capabilities to subsea production operations including production from templates. Make recommendations for enhancing current practices as necessary and appropriate.
	Education	24. **Immediate Action:** Develop a historical context document of marine well control and containment that includes an extensive reference list. This could enhance Task Force work and will be a good base document for the industry.
	Evaluate new technology for subsea containment	25. Research and Develop Capability - Evaluate new and evolving ideas for subsea containment including open capture devices that would have separation capability. R&D should be a key part of the Containment Company in which all industry can participate. All the R&D programs will work collaboratively with appropriate organizations like RPSEA and Deepstar to ensure maximum leverage in the R&D program.

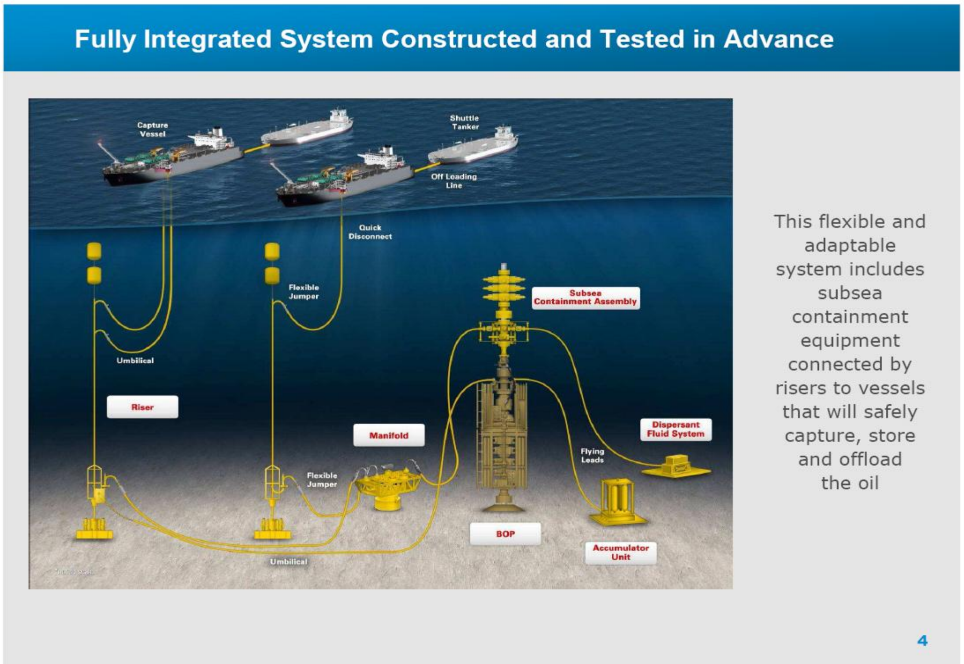
Focus Area	Description	Summary of Recommendations
Relief Wells	Relief well planning during well planning and permitting.	26. **Immediate Action:** Via focused workshops, determine and make a recommendation on the most effective methods and information that should be included in well plans regarding relief well drilling planning. Ensure full coordination and eliminate duplication with other groups' initiatives.
	Technologies for Relief Wells	27. **Immediate Action:** Undertake desk research to revisit published work on relief wells. 28. Research & Develop Capability – Conduct focused interviews with experts and vendors of specialized equipment (ranging tools, etc.) Understand and support, as necessary, plans for developing magnetic ranging tools that don't require tripping the drilling assembly and other equipment that should enhance relief well capability. 29. **Immediate Action:** Write a white paper on relief wells that evaluates the feasibility and desirability of pre-drilling relief wells. This task is complete.

Figure 1: Excerpt from Michael Bromwich presentation at BOEMR Forum on August 4, 2010 [1]



The slide above illustrates, generally, the actions and decision process employed to contain effluent from the Macondo well. The Task Force intends to deliver more rapid response with full containment via Containment Company such as the MWCC.

Figure 2: Well Containment Systems [5]



The figure illustrates the initial design concept of the recently announced Marine Well Containment System. Other subsea containment system concepts are available for contractors in the GOM.

Appendix 1: Excerpt from DOI publication dated May 27, 2010 – Recommendations relating to Wild Well Intervention

C. Wild-Well Intervention

Recommendation 9 – Increase Federal Government Wild-Well Intervention Capabilities

Blown out, or —wild wells, involve the uncontrolled release of crude oil or natural gas from an oil well where pressure control systems have failed. The Federal Government must develop a plan to increase its capabilities for direct wild-well intervention to be better prepared for future emergencies, particularly in deepwater. Development of the plan should consider existing methods to stop a blowout and handle escaping wellbore fluids, including but not limited to coffer dams, highly-capable ROVs, portable hydraulic line hook-ups, and pressure-reading tools, as well as appropriate sources of funding for such capabilities.

Recommendation 10 – Study Innovative Wild-Well Intervention, Response Techniques, and Response Planning

The Department will investigate new methods to stop a blowout and handle escaping wellbore fluids. A technical workgroup will take a fresh look at how to deal with a deepwater blowout. In particular, the workgroup will evaluate new, faster ways of stopping blowouts in deepwater. The technical workgroup will also address operators' responsibility, on a regional or industry-wide basis, to develop and procure a response package for deepwater events, to include diagnostic and measurement equipment, pre-fabricated systems for deepwater oil capture, logistical and communications support, and plans and concepts of operations that can be deployed in the event of an unanticipated blowout, as well as assess and certify potential options (e.g., deepwater dispersant injection).

References

1. Bromwich, M., *Strategies for Well Control and Containment in Deepwater*, in *BOEMRE Forum*. 2010, Department of Interior: New Orleans, Louisiana.
2. Danenberger, E.P., *Outer Continental Shelf Drilling Blowouts, 1971-1991*. 1993.
3. Danenberger, E.P., *Submission to Commission of Inquiry, Montara Uncontrolled Hydrocarbon Release*. 2010.
4. Izon, D., Danenberger, E. P., Maynes, Melinda, *MMS study of OCS blowout incidents 1992-2006.* Drilling Contractor, 2007(July/August, 2007).
5. Sara Ortwein, ExxonMobil; Melody Meyer, Chevron Entergy Technology; Charlie Williams, Shell Oil; Steve Bross, Conoco Phillips, *Safe, Protective Drilling Practices in the Deepwater Gulf of Mexico*, in *BOEMR Forum*. 2010: New Orleans, Louisiana.

Workshop Results

Final recommendations and findings from the workshop face-to-face discussions

- **There is not a technical limit to designing and building Containment Capabilities for deeper GOM water depths**

Current containment systems are qualified for 8,000' water depth (WD). This is primarily limited by the risers from the sea floor to the water surface. The capping stacks are qualified up to 10,000' WD and rated to either 10,000 or 15,000 ksi. The principle limit here is available hydraulic actuation volumes and pressure to close the capping stack rams. Accumulated fluid storage systems and subsea pumps have reduced capacity as water depth increases. This issue can be accommodated in the equipment design, and is the same as the production and drilling equipment thus there is not a technical limit.

The two containment companies are in various stages of building or designing containment systems for 10,000' WD with capping stacks rated to 15,000ksi. These systems will begin delivery in 2012. The GOM has an approximate maximum water depth of 14,000'. However, there are no prospects currently being considered in more than 10,000' water depth.

Even though there is not a technical limit – the Task Group felt that a survey of the number of support and logistic vessels that can work in 10,000' WD at high equipment handling loads (+/- 300K lbs) should be done. This is to assure there are adequate numbers of such vessels to handle a containment response. However, it is quite unlikely that this is a problem since all permit holders must clearly identify their logistics support equipment as part of the permitting process. The permit holder must be able to demonstrate that there is adequate equipment and they know how to access it.

It should be noted that the current containment designs do have a limit on shallow water use – generally not less than 500' WD. Some components such as the capping stacks could be used. However, riser systems, dynamically positioned vessels, subsea systems, may have operational limitations in shallow water.

INCIDENT COMMAND

It is generally agreed that the Macondo containment response was on a scale and scope never conceived by traditional incident command structures and drills. This is confirmed by all the reports and studies of the incident. Although the response was remarkable under the circumstances, there are many areas for improvement and improved planning for and by incident command. Six areas were identified in the Workshop.

First was the decision making process. There were a large number of organizations involved including state and local organizations – (regulators, agencies, law makers, law enforcement, etc.), private companies (responsible parties, contractors, suppliers, companies offering assistance, etc.), and private individuals. All the decisions had aspects and considerations that were technical, political, and media/public perception. Many of the government organizations did not have the technical knowledge or technical capability for working in deep water. In this situation it was quite unclear how to make decisions even though "authorities" were relatively clear. It is generally agreed that this caused some decisions to be elevated to unnecessary levels. It was felt that considerable improvement in the speed and effectiveness of decision making would benefit by discussions and workshops amongst the all the containment response groups. The result of these workshops would be a pre-agreed decision process.

Second were the roles and responsibilities. As noted above, the large number of groups involved made identifying the roles and responsibilities unclear. This included the role and especially the liabilities of the industry expert group convened by the DOI. This group was considered to be an important source of independent advice to DOI and incident command, however, their official capacity was never resolved including how they were to interact with other involved groups, how their information was to be used, or their liabilities – if any. The workshops and workgroups resolving decision making should also resolve the roles and responsibilities of the groups and organizations that may be involved in a future containment response.

Third, was the training and standards for response contractors. Because of the size and scope of this containment response, the contractors that were involved by incident command had not been trained for such an incident including how they were to work in the incident command structure. It is recommended that such training and standards be developed for responses of this scale. One suggestion is to request that the new Center for Offshore Safety develop such standards and training for the industry.

Fourth, was specialized decision making on when to cap a well and the capping point. There are two key technical considerations that have an important effect on the timing of both temporary and ultimate containment. The first is where to disconnect and thus where to install the well cap. In most cases, the BOP sequencing will deliver disconnect of the LMRP yielding the LMRP connection point as the available and preferred connection point. The second is when to do a disconnect, if it did not occur as part of normal BOP sequencing or because an alternate connection point for the capping stack is more desirable. Capping/disconnect points include: the stress joint connection, the LMRP connection point, and the connection point between the BOP and the wellhead housing. There are various risks to be considered at these disconnect/connect points if something other than a normal LMRP disconnect has occurred. The principle one being the possibility of a temporary flow increase. A last technical consideration is well integrity. As part of the design and permitting process it is determined whether the well design and geology supports cap and shut-in, cap with subsurface pressure relief, or cap and flow to a containment system. A technical determination must be made at the time of cap installation that the well integrity has not been affected by the uncontrolled flow and in fact is the same as the original design. In the unlikely event well integrity has changed, this must be accounted for in the capping plan including the possibility that pressure under the cap must be controlled to some maximum level. Since these technical considerations and decisions are both an important and a specialized decision, the task group recommends that the decision methodology be pre-planned by a joint industry/government workgroup. This work has been started by the API Capping Stack workgroup. Consideration of the decision making process will be helpful, but plans, equipment, and procedures are now in place to take the necessary actions on capping a well.

Fifth, was preparation for a massive Simultaneous Operation (SIMOPS). One of the principal jobs of incident command in the Macondo response was managing a vast fleet of vessels, planes, helicopters, ROV's, and people. The lessons learned from this should be captured for the future. Additionally, improvement areas identified from the Macondo incident command should be actioned and included for development and training of future Incident Command centers and SIMOPS implementation.

Sixth, was how to enhance interagency coordination. Again the scope of this response resulted in the involvement of a large cross section of government organizations including the Military (i.e. FAA, DOD, Navy, US Customs, etc.). As part of decision making, roles & responsibilities, and SIMOPS improvement, interagency coordination improvement opportunities should also be addressed.

TECHNOLOGY

The Task Group during the workshop identified several areas for future technical work and development.

Dispersants were a key part of making the work area of the containment response free from VOC's. They also appear to be a key part of preventing oil from reaching the beaches. The effects and effectiveness of dispersants is now the subject of many studies. The Task Group supports the technical work of the API Oil Spill Preparedness & Response Subcommittee.

It is important to define how the use of dispersants will be authorized in the future which must be based on technical review and assessments.

Further work should be conducted to determine if technical improvement can be made to current dispersants for use in subsea injection. It is possible that solvents could be removed as these were specific for ocean surface spraying.

Also it is important to determine optimum dispersant injection and mixing rates when used subsea.

The Task group supports technical work on subsea mixing equipment that could improve mixing and reduce dispersant use rate. This might be particularly important if dispersants are used at shallow water depths where dispersant mixing is likely problematic.

Lastly, an industry survey should be conducted to determine if storage, logistics, and transportation of both dispersants and methanol needs to be increased above that currently available. The transportation of these chemicals requires specialized equipment and potentially specialized boats. Adequate capability and capacity for this exists today and is part of the permitting process. But it should be determined if any enhancements will be needed or beneficial for the future.

Well Integrity determination is key to determining the timing and type or response needed to cap, contain, and potentially kill & control a well that is out of control. If the well integrity is compromised, capping and kill operations could cause an additional well breach (subsurface or at the sea floor) making further response significantly more difficult. This situation has been improved as the new NTL No. 2010-N10 from BSEE results in most wells being initially designed for capping with full shut-in or subsurface pressure relief without seafloor breach. However, confirming the current well integrity prior to capping should be studied. This could be done thru instrumentation or remote sensing. The four major areas to determine integrity are the wellhead & seals, pressure integrity between casing strings, the cement, and containment of fractures & fracture growth by uncontrolled flow of formation fluids into open subsurface formations. All of these require studies and extending technology. One existing technology which the Task group supports is measuring the pressure between the primary casing string and the secondary casing string which is commonly called the B annulus. Knowing this pressure assures that these two casing strings are not communicated via the wellhead seals or by some issue in the casing, connections and cement. Knowing that the primary and secondary casing strings have the integrity of their original design is a key piece of technical data that greatly simplifies containment planning and in many cases reduces the overall timing of a response.

Well shut-in devices & supplemental shearing equipment needs to studied for new technical concepts. In particular the use of unconventional methods like shaped charges should be developed. These charges could cut essentially any tool that is used in the well. Current shear rams are limited by their activation pressure and mechanical cutting configuration to primarily cutting drill pipe bodies. Explosive devices could also be used to intentionally deform the casing resulting in complete or partial shut-in for a well that was out of control. This is a concept similar to a safety valve in a production well. This has been considered in the past by using mechanical seals. These were limited by the fact that they were conveyed on the drill string and needed mechanical annular shut-in devices. There are projects in the industry that are pursuing these new novel ideas but more work should be done.

MWD Ranging Tools are used to help direct the intersection of the relief well with the well that is out of control. This is generally done with electromagnetics. These tools are highly specialized and seldom used. They have not been available in measurement while drilling (MWD) configuration. The consequence is that active ranging and directional work while drilling could not be done. Drilling would have to stop and the tools run on wireline. Then the drilling and directional drilling work would start again. The Task Group felt that the MWD capability for ranging had been developed during Macondo. However it is not confirmed. The task group recommends that this should be confirmed and if there are still technical gaps and improvements in this capability and technology they should be addressed and resolved.

High Resolution Seismic can conceivably be used to determine well integrity on a well that is blowing out underground. In particular, seismic can be used to determine if the well has fractured to the surrounding subsurface formation, the rate of the fracture growth, and whether the fracture could connect with other faults or the sea floor. The Task group recommends the feasibility of this should be studied.

Riser Release at the lower flex joint should be technically evaluated. As noted at Macondo, the riser connection at the LMRP is usually a “permanent” connection like a flange. This connection was separated at Macondo and the capping stack installed on the bolted connection. This is complex and difficult work for a ROV. It is conceivable that an automatic release similar to the LMRP release could be designed for this connection. This should be technically studied for feasibility and risk/benefit. This is a difficult location as it is at the base of the stress joint for the marine riser. Generally this connection point is rated at +/- 5000psi where as the BOP’s are rated at 10,000 to 15,000 psi. By increasing the pressure capacity of this connection some of the limitations on installing capping devices or doing well kills at this connection location could be eliminated.

Hydrostatic Assist to Shear should be evaluated. As noted above, traditional shear rams are limited by the pressure and volume capacity of their accumulator systems which store energy for their activation. Using the hydrostatic pressure of deepwater to assist with activating and energizing the shear rams could increase their capacity.

Industry Survey of DW Hydraulic Power Unit Capacity should be conducted. As noted in other sections, it is very important to have sufficient rate, volume, and pressure capacity to activate many subsea devices such as debris clearing, cutting, secondary BOP activation, activating releases, etc. This is difficult in the DW as this energy cannot be effectively supplied from the ocean surface because of the distances and the stresses on conveying lines and pipes. Also it is difficult to generate the pump rates and forces necessary at the sea floor because of the high hydrostatic pressure. Companies have and are building seafloor DW hydraulic power units to solve this problem. It is important to determine if the industry has sufficient capacity in this regard and that the capacity is correctly located to appropriately reduce response times.

Determine if there is sufficient benefit to the development of System/Subsystem Simulators for Containment Training. If developed, these should include the capability for evaluation of the students. Cap, Contain, & Flow systems are large and complex systems and there is the possibility they would face varying response scenarios. Because of the scale of the equipment it might be difficult to conduct some aspects of the training as frequently as is desirable. For these situations a simulator could be used that simulates individual components or even a full flow system. It needs to be determined by the containment companies and their members if such simulators are needed as part of a comprehensive training plan.

REGULATIONS

The Task Group determined there were opportunities for regulatory improvement during containment responses.

Using the Administrative Procedure Act (APA) Process Rulemaking & Collaboration is extremely important to developing new regulations via expert input, additional review, and collaborative discussions regarding the most effective regulations to achieve the common goals in preventing and responding to incidents.

Regulatory requirements should be focused on major hazards. The Task Group recommends that BSEE develop a process utilizing appropriate workshops that can identify the major hazards and mitigations to prevent loss of well control. This would be similar to the "bow-tie" process used by some companies and would allow regulations to be prioritized and established that focus on establishing and maintaining well control.

Streamline approval for Subsea Dispersant Use. As noted earlier and despite previous EPA approval, it is unclear how to request and achieve approval for dispersant usage in a response to a loss of well control event. This process needs to be both clear and timely enough to allow the dispersant to be fully effective. Since dispersant use is one of the key early response items for both dealing with the oil and providing a safe work environment, it is very important that this approval process be addressed. As part of clarifying this process, any additional requirements such as monitoring during dispersant use need to be clarified.

Resolve Containment Qualification Testing. Containment systems involve a large number of subsea components. As noted in the Macondo containment, deployment of such a system is a massive effort. Additionally there is a large amount of re-conditioning of equipment necessary to store the equipment and prepare it for re-use if it is deployed. A full deployment is not necessary to test and demonstrate the capability and functionality of a containment system. As noted early, the individual components of the system are typical subsea equipment that is commonly deployed and used in DW. The industry does not for instance pre-deploy a subsea production system purely for testing. Testing is done on the surface and can include pressure testing, function testing, hook-up, and dimensional and connector verification. It needs to be resolved what verification/qualification testing is required.

OPERATIONS / STANDARDS

The Task Group in Topic # 5 identified several opportunities to develop industry standards as well as operational enhancements that should be considered.

Industry Recommended Practices/Standards for Capping Stacks. These include:

- Develop clear consistent definition of Containment, including technical terms for containment components. There are multiple responses that may be utilized to regain control of a well, including capping a well (full shut-in) and/or capping a well but with a flow system to the ocean surface. There are also variations of capping only including capping and fully keeping hydrocarbons within the well wellbore and capping with pressure being relieved to a subsurface formation. The use of the word containment has thus been variously used or misunderstood because of all of these possibilities. An API/BSEE work group should come up with recommendation for common industry definitions.
- A capping stack recommended practice (RP) should be created to define functionality and characteristics of a capping stack. There are many variations of design already in existence or planning including single ram, multi-ram, inclusion of diversion spools, and many variations of control systems. It is generally agreed that capping stacks are not part of the Standards or Regs for BOP's. The RP should also consider tiered capping stacks and their classification such that optimal and fit-for-purpose caps are available for various applications and needs. Consideration should be given for both large and small caps. Small caps have advantages in speed and ease of deployment, availability of logistics vessels, air transport, and can fit within riser systems on floating production structures. An API RP Workgroup is meeting and getting organized to develop this RP.
- There is not an RP for Top Kill in the industry. It is considered important that it be developed. The RP should consider clear definition of the process as well as a variety of variations suitable for different kill scenarios. Also, it needs to be considered if Top Kill capability should be included in the functionality of a cap. The Capping Stack RP Workgroup should add this to its work.
- The RP workgroup should also do a technical evaluation of the importance and technical capability to affect a soft landing of a capping stack.
- Many caps now are quite large (more than 100 tons). The RP workgroup should determine what are the reasonable loading and bending moment limits of the wellhead systems to accommodate these stacks. This is particularly important if

a cap is landed on a BOP. Additionally, the foundation load capability of the well itself to accommodate capping should be considered.

- The existing Containment systems were initially designed to address a single subsea drilling well similar to the Macondo scenario. Some of these systems have already been adapted for some scenarios on floating production structures. Work should continue to identify other reasonable containment scenarios and applications to guide the continuing development of the well caps and the rest of the containment system to address other possible industry containment needs.

An RP needs to be developed for Containment Planning. This RP would standardize the forms, planning process, and data that companies would need as part of compliance with NTL No. 2010-N10. The existing Containment JITF should set up a task group to do this. They will take advantage of all the work already done by the containment companies.

An industry task group should continue to work with BSEE and the Blowout Risk Assessment JIP (BORA) to integrate the results of BORA into the Wellbore Screening Tool and the screening process as appropriate. This task group could also assist in evolving the tool for more scenarios, to resolve technical issues like gradients, and to include risk/barrier methodology and considerations as appropriate.

There are recommendations for potential enhancements to BOP designs:

- As mentioned in an early section, blind-shear rams generally only have the ability to cut the drillpipe body. They cannot cut the connections or the other larger and heavier wall equipment that is periodically run into the well. There are emerging concepts for increasing the shearing capability and better centering the items to be cut. This and other concepts should be pursued. Also availability of BOP designs for 20ksi and greater are very limited. Also the physical size of these designs is an issue. Enhanced technology and design concepts could be quite beneficial for ultra-HP BOP designs. Also, new designs and materials should be considered for BOP's to improve their corrosion and stress corrosion cracking resistance and their survival under high rate flow conditions, as well as the effect of flow rate on shearing capabilities. All these ideas should be addressed and matured by API Subcommittee 16 and the Standard 53 Workgroup.
- BOP's generally have limited capability to monitor pressure, temperature, ram position, volumes of control fluid pumped, etc. This capability is especially limited when the riser is disconnected. There needs to be capabilities added to BOP systems to allow external data collection and monitoring of key data from the BOP's. This should also be addressed by API Subcommittee 16 and the Standard 53 Workgroup.

Document Mutual Aid Rig Requirements. The interim MWCC containment system and the Helix containment system depend on drilling rigs as part of the response. These containment organizations should assure that availability and commitment of these rigs is continuously understood and will provide suitable mutual aid for a containment response.

COMMUNICATIONS

Because of the many groups, companies, organizations, agencies, and communities that are involved in a large containment response, communication is a critical factor in ensuring confidence in, speed, and effectiveness the containment response. Enhanced communication and protocols should be considered in the following areas:

- Interagency Communication (EPA, NOAA, etc.)
- Regular meetings of Industry Groups and Containment Companies to share containment learnings and best practices
- Debris removal is the responsibility of the “responsible party” needing the containment response. There are many techniques for and providers of this service. Thus it is important that containment companies, operators, and suppliers have communication and sharing to improve the overall understanding in the industry of this part of response.
- Because of the wide impact of a large containment response Community Outreach & Education should be conducted with potentially affected communities and local governments. This same communication should occur with NGO’s. This work should be done by containment companies and operators.
- Academia has not been as involved in the communication regarding containment capability and technology as they should have been. Nor have they been involved in idea generation, technology creation, or review of containment capabilities. Both of these issues should be addressed.

Session 6:
Risk Assessment of Critical Operations and Activities

Chair: Dan Fraser, Argonne National Laboratory
Co-chair: Steve Kropla, International Association of Drilling Contractors

1. White Paper
2. Addendum to the White Paper on the Need/Process for Risk Assessment of Critical Operations and Activities

Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

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Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

General Purpose

This white paper will be used as baseline starting point for discussions in the Topic #6 breakout session at the Nov 2-3, 2011 BSEE/ANL/Industry workshop on the *Effects of Water Depth on Offshore Equipment and Operations*. This paper is meant to provide a brief background of Topic #6 and identify current trends and challenges. This paper is intended to address:

- o Current technologies and challenges with implementing those technologies.
- o Trends and/or notable technologies envisioned for the near and long-term
- o Coordination and communication to help align the efforts of industry and regulatory agencies
- o Human Factors in safety (e.g. training, procedures)

Background

Prior to the Macondo accident in 2010, the MMS performed an analysis of the commonalities among accidents occurring between 2000 and 2007 on the Outer Continental Shelf (OCS). This analysis considered 33 accident panel investigation reports and an additional 1,443 incidents. It determined that the root cause of most safety and environmental accidents and incidents on the OCS over that period was due to a failure in 4 key offshore operator management system elements:[1]

- o Hazard Analysis
- o Management of Change (MOC)
- o Operating Procedures
- o Mechanical Integrity

After Macondo, the regulator's preliminary investigations of that accident, along with their previous analysis, prompted them to publish a new regulation, 30 CFR Part 250 subpart S (SEMS), in October 2010.[2] This new regulation mandates (among other requirements) that the 4 elements as well as all other elements of a safety and environmental management system per API RP 75 (totaling 13 elements), be implemented by OCS operators.

The successor to the operational aspects of the MMS, the BSEE (as of October 2011), still believes that improvement in the implementation of these elements is a priority for the offshore oil and gas industry.[3] Yet the new regulation does not provide guidelines as to how, for example, to integrate hazard analysis, MOC, mechanical integrity, and operational procedures into a process risk management methodology that can minimize the likelihood and/or the consequences (i.e. reduce the risk) of another accident on the OCS that leads to loss of life or significant damage to environment.

[1] U.S. Federal Register, Vol. 74, No. 115,Wednesday, June 17, 2009, page.28639
[2] U.S. Federal Register, Vol. 75, No. 199, Friday, October 15, 2010, page 63610
[3] Remarks by BOEMRE official, David Dykes at June 28, 2011, OOC meeting, Robert, LA.

Such an aggregated approach toward process risk management is needed not only for the industry itself, but also to help form the basis of an ongoing dialogue between the industry regulators and the industry – a dialogue based on data, facts, and demonstrable best practices.

Scope:

The focus of this paper is to engage a group of Subject Matter Experts for the November 2-3 Workshop discussion on how risk based strategies are being and may be used in the near future to improve risk methodology for managing offshore operations. For purposes of this discussion, "risk" is defined as the product of the probability of an undesirable event and the consequences of the event. The focus of the discussion is on critical operations and activities, defined as those with large-scale consequences. The goal is not just to prevent "Macondo" type events, but also consequential events that may arise from altogether different circumstances.

Risk categories in this industry include safety (preventing people from getting hurt), environmental (maintaining well integrity to prevent uncontrolled releases), economic (determining whether it is a good investment to drill a well), and political. Risks can be managed through identification, assessment, controls, response, mitigation and remediation. The scope of this paper includes approaches to managing environmental and major process safety risks. While also important, personal safety (e.g., slips, trips, and falls), economic, and political risks are not addressed in this paper.

This paper focuses on risk assessment (and management) related to the following offshore processes:

- Well design
- Well drilling and construction
- Well completion
- Critical topside and subsea operations

(Intervention activities need to be included in an overall risk management program although these are covered separately in White Paper number 5, and will not be discussed as part of this workshop session.)

Listed below are three definitions used in this paper

- Industrial risk – focuses on the individual to avoid injury to him/herself and for others to avoid injury to co-workers or other parties. May also be called "operational safety," "personnel safety" or similar.

- Process risk – focuses on multiple and/or intertwined (though perhaps not communicated or understood) decisions, operations, and actions that may affect the overall safety of a facility.
- Structural risk – focuses on inherent design and function of structural components and mechanical equipment that may affect the integrity of all or part of an individual barrier or multiple barriers designed to minimize risk to a process or facility.

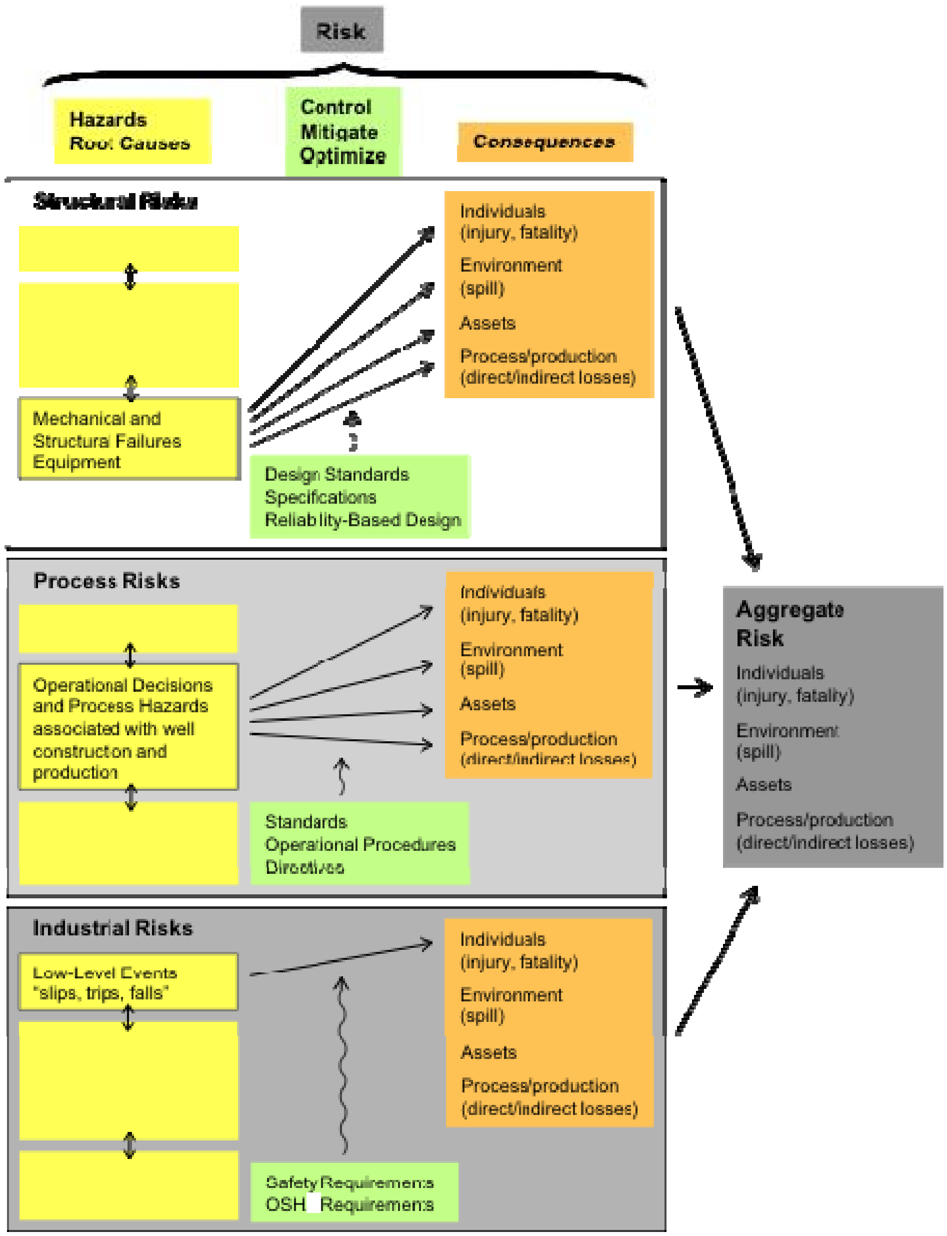


Figure 1. Integration and Aggregation of Three Types of Drilling Risks

The integration and aggregated effect of these three types of drilling risk are illustrated in Figure 1. The tools, techniques, programs etc. required to manage different forms of risk such as Process and Industrial safety can sometimes be the same (for example a Work Permit system) and in other cases may have very different approaches. Quantified Risk Assessments, for example focus on Process Safety whereas PPE (Personnel Protective Equipment) is very much an Industrial Risk issue.

The focus of this paper is tipped toward Process Risk although all the risks mentioned above are coupled.

It is expected that not all of the methodologies and techniques for the future will come from inside the oil and gas industry as multiple industries (including: refining, aviation, aerospace, chemical industries, and nuclear power operations) each have strategies for managing risk that may be informative for the oil and gas industry.

Also it is not within the scope of this paper to exhaustively cover risk management, rather it is to identify areas that are seen as highly important to discuss with key stakeholders at this juncture in the ongoing evolution of the industry.

Introduction:

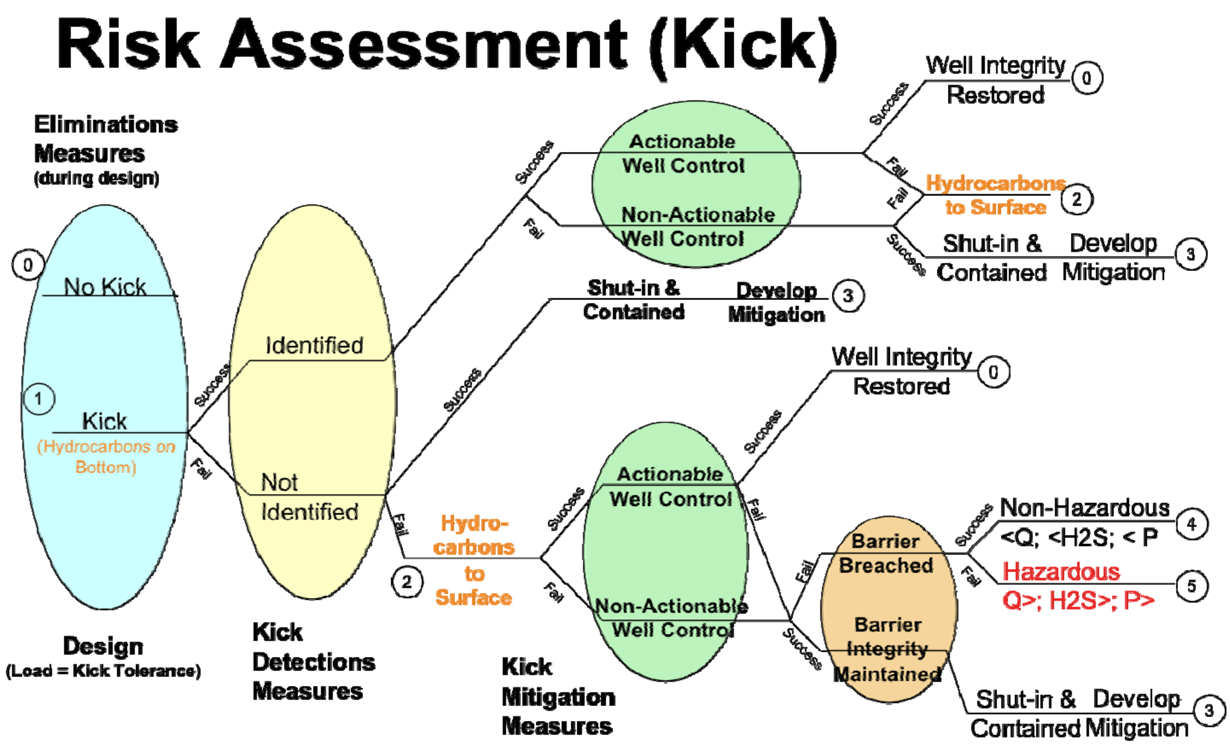
It must be accepted that no endeavor is totally risk-free. The well construction process involves a continuous series of decisions that are continuously increasing or reducing risk – the challenge is measuring, modeling, weighing the risks of available options, making sure this information is communicated to the rig and operational managers, and effectively utilizing this information while the rig is operating. Since the focus is on preventing high consequence safety/environmental events it should be understood that risk assessment may be long-term in the design phase, medium term during the process of optimizing the drilling program, or short-term when involving dynamic activities in progress on the rig floor. Consideration should be given to the factors that influence decision-making and adopting practices that can manage the risks inherent in the various phases of well design and construction.

Risk assessment is familiar to the oil and gas industry, and there have been a variety of efforts to describe, classify, and even to create standards. A brief history is provided in Appendix 1. Also, there is a noteworthy effort currently underway on a joint industry project (JIP) being led by the OOC to help standardize a methodology for risk assessment in the oil and gas industry. Creating an accepted methodology for such risk assessment is an important first step. On other fronts, some in the industry are pursuing the strategic use of mathematical approaches and modeling. Such approaches enable users of the model to obtain useful numerical information such as how the risk is changed by differing environmental dynamics. One strategy being proposed by the industry is to adapt the principles utilized in ISO TR 10400:2007 (Petroleum and natural gas industries -- Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing) to process risk management in an operational setting. This approach is discussed in Appendix 2.

Discussion:

Process risk management

Process risk management occurs during drilling and completion service delivery, both of which rely heavily on the design and structural integrity of the well. In a real-time sense risk parameters are dynamically changing as the well is being constructed. It is important to translate these changes into to effectively communicate these changes into information that can be used to inform process management on the rig. Risk-informed decision making implies that decision makers at all levels have the necessary information as well as the understanding of how to use that information to inform their operational decisions. See figure 2 as one example.



	Design		Detection			Control		Barrier	
Reliability	No Kick	Kick	Pore Pressure Prediction	Pressure Monitor	Flow Controls	Actionable	Non-Actionable	Breached	Integrity Maintained
High									
Medium									
Low									

Figure 2. High Level Event Tree for a Kick -- This diagram shows some of the risk management stages for process decisions in managing an event such as a kick.

Risk management systems serve as a foundation for process decisions. With the risk management process, the possible outcomes of each activity are determined and contingency plans for addressing undesirable scenarios are developed. With lists of risks associated with drilling well offshore, there can be two types of risk control mechanisms.

- Proactive control
- Reactive recovery

Proactive control addresses threats through effective risk management. These activities include audits, safety case, equipment inspection, well integrity review, and safety management system design. Reactive recovery aims at consequence mitigation. It also mitigates the risks associated with a poorly controlled incident. (There is currently an IADC standard for adopting a safety case as expressed in HSE Case Guidelines for MODUs version 3.3; but there is currently no industry consensus on whether a safety case strategy should be implemented or not.)

Generally, process excellence requires four attributes:

1. Equipment that is fit for the purpose;
2. Material fit for the purpose (e.g. barite, cement, …);
3. Personnel who are competent and fit for purpose; and
4. An effective management system

Regardless of how management is approached, human behavior and decision making are some of the most critical safety components. It is necessary to achieve a balance between levels of risk that are deemed acceptable (both by industry and regulators) and what is physically possible. When this is accomplished, process excellence can be achieved.

The following false premises must be addressed:

- Policy and Procedure alone are not sufficient management capabilities. Paper does not protect people. Human behavior that is in compliance with sound policy and procedure is what is needed.
- A set of documents does not constitute a management system. The system must drive a process that becomes self-sustaining.
- Safe Work Practices enhance <u>personal</u> safety of rig-based workers, but they are not enough. The management system must be extended to the larger realm of operations.

Some Important Aspects of Process risk management

Tools and Processes

There are numerous methods available for conducting hazards analysis on operating facilities or new projects. Both API RP 14J (Recommended practice for design and hazards analysis for offshore production facilities), and the IADC HSE Case Guidelines for MODUs provide guidance on some of the common techniques and selection of the appropriate methodology. A key philosophy is selecting the techniques that are commensurate with the inherent risk and complexity of the facility and related processes. Examples of factors that influence the risk include size and complexity of the facility, types of hazards, personnel exposure and proximity to environmentally sensitive areas. Some of the techniques that have been applied in offshore well construction operations include:

- HAZOP (Hazard and Operability Study)
- HAZID (Hazard Identification Study)
- HEMP (Hazard and Effects Management Process)
- SHIDAC (Structural Hazard Identification and Control Process)
- FMECA (Failure Modes, Effects, and Criticality Analysis)
- LOPA (Layer of Protection Analysis)
- QRA (Quantitative Risk Assessment)
- PRA (Probabilistic Risk Assessment)

Many of the methodologies used on shallow water facilities, such as HAZID, HAZOP, and LOPA are equally applicable to deepwater facilities. However, when considering fire and blast hazards, approaches and assumptions used for shallow water facilities may not be sufficient for deepwater facilities. Use of advanced modeling programs such as computational fluid dynamics software are typically used to more fully assess these hazards.

Compared to shallow water operations, deepwater operations have a number of challenges that affect the associated hazards and risks. While deepwater does not necessarily imply higher reservoir pressures, there will be high pressures at the wellhead due to water pressure. These have a direct impact on the mechanical design of well components and drilling and well control equipment. Operating in deep water can also significantly change the characteristics of the risk and in some instances introduces novel risks to operating in shallow water. Differences result from deep water facilities having larger topside facilities, export oil and gas systems operating at higher export pressures, larger inventories of hazardous material, topsides production modules with more congestion and/or confinement, and generally a larger number of personnel on board. These differences can consequently result in higher blast overpressures and more severe fire and smoke scenarios, potentially resulting in significantly higher risks to personnel and the environment then when compared to the typical shallow water facility. Additionally, the subsea components and production and export risers are often at the limits of current technology and may require the application of new technology such as subsea High Integrity Pressure Protection Systems.

Additionally, the general hazard identification and risk assessment process addressed for well design and well execution activities should be equally applicable to topside and subsea systems. The differences would be the details such as initiating causes and detailed barriers. (The Barrier Philosophy incorporated in API RP 96 (Deepwater Well Design and Construction) and API/IADC Bul 97 (Well Construction Interface Document Guidelines) has been recognized as a valuable principle that crosses multiple risk areas.)

Risk Communication to onsite decision makers including contract personnel

Some risks in the well construction process are inherent in the large scale of the equipment and the isolated operating location of the rig. These risks do not change much from day to day. Examples include hurricane exposure and dropped objects (risk may be seasonal or affected slightly by weather, but are present each day). However, some risks associated with maintaining the integrity of the wellbore and the rig do depend strongly on the particular operation during the well construction process and on the particular details of a well's location. Examples include drilling into a subsurface formation with unknown pore pressure and cementing a high-pressure gas zone. These risks may be understood and anticipated better by the operator who has knowledge of the anticipated subsurface conditions and the particulars of the wellbore design than by the rig contractor and other contractor personnel on the rig. Risk assessments are often performed by office-based personnel and the relevance and findings must be communicated to rig-based personnel. This enables rig-based supervisors and other operations and engineering personnel to be prepared to make decisions (possibly under pressure) that weigh risks and benefits against pre-defined acceptance criteria. Key outcomes from risk assessments must also be communicated across organizational boundaries, and across the various phases of the project life cycle.

It is important to

- establish clear expectations in commercial agreements regarding risk;
- make risk assessment a priority in the same way HSE is prioritized; and
- have core competencies in both operator and contractor organizations to understand risk.

There has been some recent important progress in this area through development of API RP96 and Bull 97 (both still in draft form) by the IADC and API. RP96 emphasizes barrier design and management as key contributors to total well system reliability with respect to well design, construction, and operation control. Bull 97 links the operator's and drilling contractor's safety and environmental management systems, and describes a formal mechanism for the operator to communicate well-specific information such as the basis of design, well execution plan and risk assessment to the drilling contractor.

Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

A remaining step is to ensure processes are in place to translate the risk assessment results for the individual well's unique conditions into hourly highlights for the rig-based personnel, enabling them to make risk-informed decisions in response to any event. One tool that has been applied successfully to facilitate communication between office-based and rig-based personnel is the "Drill Well on Paper" exercise (DWOP). This exercise brings together the office-based and rig-based perspectives on the well and can be an effective tool for risk and hazard communication in addition to its alternative role to identify optimization opportunities.

❋ How does the rig crew member know about the particular well integrity risks for that tour's planned activities? Does he understand the consequences of various possible responses to things he may observe during his tour (shift)?
❋ Do rig-based personnel understand the types of events that have the potential to escalate to major consequences like the loss of the rig or loss of well integrity or loss of the reservoir asset? Do they understand the key mitigation steps that are intended to prevent the escalation? Can they identify these situations developing and shift their focus to mitigation?

Managing Downhole Uncertainties

The management of downhole uncertainties is an important part of process risk management. In many cases drillers do not know with a high degree of certainty what is downhole until they begin drilling. This is especially true in new fields, but there can also be uncertainties in mature fields as well. There is also uncertainty in defining abnormal or upset conditions associated with events such as kicks.
❋ What are some of the strategies currently being used to manage downhole uncertainties?
❋ To what degree have Predictive Pressure Tools been adopted by the industry?
❋ Where do new technologies such as dual gradient drilling fit in to the overall risk picture?

Limitations of Current Process risk management Practices

Limited standard definitions and sharing of tools and processes

Notwithstanding the existence of several ISO standards, there is limited acceptance of standard definitions and sharing of tools and processes. Part of the reason for this is that risk management is perceived to be an internal affair to each company to the extent that taxonomies are sometimes identifiable and specific to an individual company or business unit within a company.
(There is currently a JIP being assembled by the OOC to perform a comparative risk assessment. Part of this effort will make an attempt at standardizing some of the terminology and processes.)

Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

Need for agreed upon Methodologies for Risk Assessment

Currently there is no commonly agreed upon methodology for risk assessment. Below is an outline that could be used for working toward a consensus on a methodology for risk assessment:

- Standardize the taxonomy
- Identify the key features of a process for managing risk
- Identify requirements to have a basis for likelihood values (leveraging references in Appendix 2)
- Establish consistent methods to estimate consequences
- Create a set of pre-defined scenarios, along the lines of those developed for the Environmental Protection Agency's Risk Management Program
- Within the 'process' gradually move toward the endorsement of the risks in the framework of the organizations' risk 'criteria'. However it is acknowledged that there is a considerable amount of engineering judgment required here. Rules cannot replace this.
- This would also require a statement about the adequacy of emergency response capabilities.
- Establish criteria to accommodate how to manage changes to the estimations as the industry evolves

Limited Common Risk Understanding for Discussion Between Industry and Regulators

As methodologies are defined, the next step is for the industry to work with regulators on an agreement for what constitutes acceptable levels of risk. As can be seen from figure 1, methodologies used in well design and construction are relevant.

Without an agreed upon common understanding for discussing systematic risk both the industry and the regulators must resort to either focusing on specific risks or inexact specifications that can have unintended side effects. These side effects, while perhaps limiting certain specific risks, can sometimes increase the overall systematic risks in non-obvious ways. Adding to the complexity of the risk acceptance process is the division of regulatory authority over OCS operations where regulatory authority doesn't align with equipment and processes necessary to control risk.

✱Manufacturer recommended inspections and maintenance of equipment is mandated by the new regulation. Is this the best approach or should operators and contractors be allowed and/or encouraged to implement risk based inspection (RBI) and reliability centered maintenance (RCM) techniques and thereby focus on their limited efforts on "critical" systems?
✱In the wake of the large spill resulting from the Deepwater Horizon disaster, the BSEE revised and increased the requirements for Worst Case Discharge (WCD) Scenario calculations to support Offshore Oil Spill Response Plans required for new offshore

Exploration Plans (EPs), Development and Production Plans (DPPs) and Development Operations Coordination Documents (DOCDs).[4] Some in the industry feel that the requirement in the new regulation for consideration of an "uncontrolled flow" event does not give credit to specific operator controls that would dramatically reduce either the likelihood or the size of a spill from a blowout, thus making the WCD volumes unrealistic. The risk contribution from a WCD (risk contribution = probability X consequence) can be much smaller than other higher probability but lower consequence events in the risk assessment chain (see figure 1). Also, increasing casing thicknesses to support the worst case discharge adds significantly more stress on the overall casing structure and can contribute to other types of failures.
Would it make sense to work toward regulations that limit the overall aggregated risk (both probability as well as consequence) as opposed to isolating lowest probability risk contributors?
In those cases where the volumes are unrealistic, what alternate approaches to calculating discharge volumes could be used to achieve the level of assurance against large spills that regulators and the general public expect?

Numerical Models for Process Risk Assessment

Numerical models as an aid toward building consensus on industry best practices

There is often diversity and disagreement surrounding technologies and processes where there is not enough data to establish consensus. In these cases, numerical models could be created that can be used as a tool for "experimenting" with new technology and capabilities. These models could be used to provide insights and statistics to help guide in the industry determination of best practices. Models like this are widely available in the automotive, aviation, astronautics, and nuclear industries and could be developed for offshore oil & gas usage.

Real time models to support dynamic Risk Informed Decision Making

Continuously running models with real time data feeds are currently in use on many oil and gas rigs. These models could be enhanced to better inform rig operators of the current risk status of their operations and thereby provide necessary information for dynamic risk informed decision making (as in other industries).

Models for training new managers

There is currently a considerable amount of change occurring within the operators and contractors as many of the experienced (baby boomers) have started to retire and new managers need to be trained. Risk models can be an invaluable tool for use in simulators for training up a new crop of rig operators and drillers.

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[4]NTL No.2010-06, June 18, 2010

Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

Findings and Recommendations

Findings and Recommendations will be noted after the workshop discussion

Reference Documentation:

Regulatory documents include:
- SEMS Rule – *BOEMRE Safety and Environmental Management Systems* 30 CFR 250, subpart S.

Industry documents include:
- API/IADC Bulletin 97 (Draft) -- *Well Construction Interface Document & Guidelines*
- API RP 96 (Draft) – *Deepwater Well Design Considerations*
- API RP 75 – *Recommended Practice for Development of a Safety & Environmental Management Program for Offshore Operations & Facilities*
- API Std 65-Part 2 -- *Isolating Potential Flow Zones in Well Drilling and Cementing Operations*
- IADC HSE Case Guidelines for Mobile Offshore Drilling Units version 3.3
- ISO 31000:2009 – *Risk management: principles and guidelines*
  - http://www.iso.org/iso/iso_catalogue/catalogue_tc/catalogue_detail.htm?csnumber=43170
- ISO 17776:2000 -- *Guidelines on tools and techniques for hazard identification and risk assessment*
- ISO Guide 73:2009 -- *Risk management – Vocabulary*
  - http://www.iso.org/iso/iso_catalogue/catalogue_ics/catalogue_detail_ics.htm?csnumber=44651.
- ISO 10400:2007 -- *Petroleum and natural gas industries - Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing*

Appendix 1: Brief History of Risk Assessment

An important milestone in the history of risk assessment in the oil & gas industry was the publication of the ISO Guidelines on Tools and Techniques for Hazard Management and Risk Assessment in 2000. This document describes hazard identification as well as risk assessment tools and techniques and is widely followed in the industry particularly for HSE initiatives in process risk assessment. The IADC used this to build additional documents targeted at specific operational capabilities such as the *IADC HSE Case Guidelines for Mobile Offshore Drilling Units*. Widespread use of documents like these in the industry has led to measurable and dramatic improvements in reducing the number of industrial injuries. (One of the important techniques is the bow-tie diagram, a graphical approach for understanding the barriers that prevent and mitigate catastrophic events.)

Moving beyond HSE however, there have been different attempts to assess risks involved in offshore drilling and production, and each of the major oil companies has implemented its own risk management program. One important document that attempts to provide generic guidelines for the design, implementation and maintenance of risk management processes throughout an organization (although not specifically the oil and gas industry) is ISO 31000:2009 *Risk Management: Principles and Guidelines*. This document has been used in some cases to develop a broader enterprise risk management approach, and has made some important contributions specifically by extending the scope of risk management to support the wide variety of strategic, management, and operational tasks of an organization through projects, functions, and processes aligned to risk management objectives.

The generality of ISO 31000:2009 means that there can be a variety of different strategies and methodologies for both risk assessment and the implementation of risk programs. Safety cases, while not mandated until the SEMS rule are an important capability being considered that requires the focused attention of the operator on risk assessment. If the future direction of the industry evolves toward safety cases, a lengthy period of time should be allowed to help develop industry and regulator consensus on the definitions and applications of safety cases.

Appendix 2: Toward a Common Methodology of Well Design, Construction and Operations Risk Assessment

In order to meet the objective of assessing the overall risk of wells for the purposes of risk comparison and risk acceptance, it is convenient to use the Barrier Philosophy incorporated in API RP 96 and API/IADC Bul 97.

The overall risk analysis can be viewed as consisting of four areas of barrier analysis, each conditional on the outcomes of the previous one:

(1) risk controlled using physical well barriers such as casing, cementing, equipment, …
(2) risk controlled by operational barriers
(3) risk controlled by a cultural/organizational infrastructure
(4) risk mitigated by subsequent containment.

In order to link these together in a risk-consistent way, a common methodology is needed.

Risk accumulates as the sum of all possible outcomes and consequences C_i weighted by their aggregated probabilities:

$$R = \sum_i C_i p(C_i)$$

In addition, the consequences C_i can be ranked and plotted versus the cumulative probabilities $\sum_k^i p(C_k)$ in a probability – consequence graph or in a Whitman plot.

The probabilities $p(C_i)$ can be found by conditional aggregation along all possible sequential paths that lead to the outcome C_i, as shown in Figure 1. Each path crosses of a (large) number of barriers b_j that operate either successfully or unsuccessfully (with probability p_{F_j}). Each bifurcation point or chance fork in the event tree shown in Figure 1, represents either a physical barrier or an operational barrier. At each barrier node, a probability needs to be determined which depends on:

- the capacity of the barrier to resist the demand or to meet its objective:
    - for physical barriers *j*, this is the failure probability p_{F_j}; it is controlled by design, testing, and quality control, and it is therefore a function of specified design criteria, design scenarios, testing and QA protocols.
    - for operational barriers, p_F represents the inability to function as intended, and it is dependent on standards, regulations, procedures, training, human factors, etc …
- the "path" followed previous to the point that the barrier is crossed or becomes active: therefore p_{F_j} is **conditional** on the outcome of previous barriers.

In order to link all bits and pieces of the risk analysis together, the above principles should therefore be respected: represent all systems/operations in terms of barriers, consider the operation of each barrier as conditional on the outcome of all (previously encountered) barriers along a given path, aggregate consequences over all paths leading to a given outcome.

Topic #6: Need/Process for Risk Assessment of Critical Operations and Activities

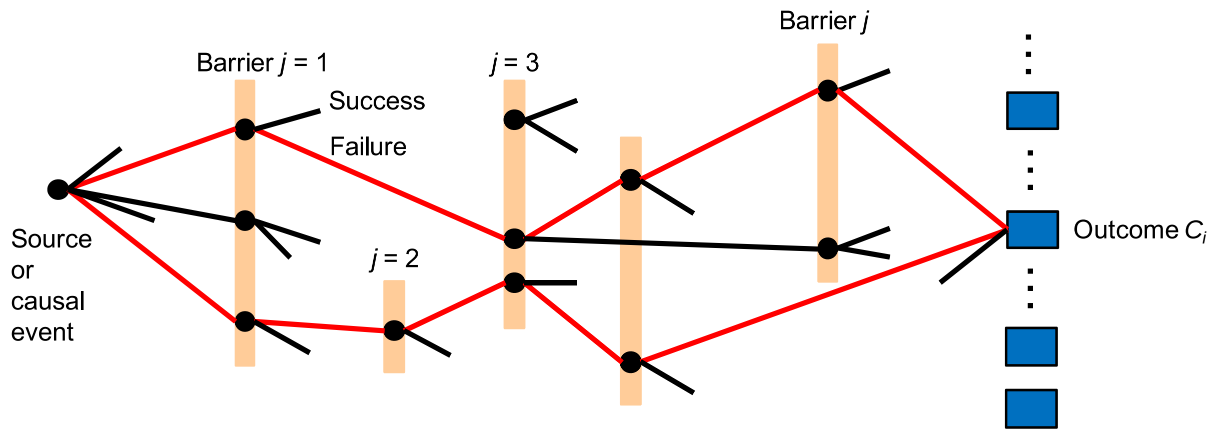

Figure 1: Well risk analysis spanning over all possible physical and operational barriers: illustration of a number of paths leading to a number of outcomes or consequences.

In order to link all bits and pieces of the risk analysis together, the above principles should therefore be respected: represent all systems/operations in terms of barriers, consider the operation of each barrier as conditional on the outcome of all (previously encountered) barriers along a given path, aggregate consequences over all paths leading to a given outcome.

Using the Barrier Philosophy on API RP 96, API/IADC Bul 97, and NTL-10 Well Containment Analysis (L1L2 Rev 1.18), the plan is to outline a methodology for a analysis of the BOD (Basis of Design).

Proposed Methodology:

1. Identify the barriers between reservoir energy and the environment for the section of well or activity to be performed.
2. Rank the failure mechanisms of the in place barriers across all flow paths using a FMEA or other process.
3. Qualify the probability of failure (***'p'***) (i.e. the probability that the loss will occur) and the consequences of failure (i.e. the magnitude of the potential loss) (***'L'***).
4. Work the risk treatments/trade-off's: avoid, control and transfer until the acceptable risk meets set criteria.

The plan is to use this methodology to design a system consisting of many components (barriers) and procedures (operational barriers).

For the system to be reliable we need the individual barriers to be reliable plus we need redundancy and robustness. The risk analysis would involve establishing the modes of barrier failure, probability of barrier failure, the consequences of barrier failure, and the system effect caused by barrier failure. Then we should also include the updating of barrier reliability based on various barrier testing methods (similar to proof loading of infrastructure) and risk treatment (avoid, control, mitigate, transfer). The last important aspect is risk acceptance -- what should the criteria be at the end of the analysis and how should this be established?

The approach is consistent with risk assessment methods used in say, aerospace, nuclear, pipeline and infrastructure risk assessment.

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A. Dahlin, J. Snaas, SPE; and S. Norton, SPE, Petroleum Development Oman.

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Appendix 3: The management and assessment of risk within the context of a UK offshore drilling operation. (Don Smith, Eni UK)

1. Introduction

This appendix presents an overview of the types of risk assessments undertaken prior to and during the drilling of an offshore exploration well[5]. It assumes that the drilling operation is being undertaken in the UK sector, with the licence holder being an E&P company which has contracted a MODU and supporting services to carry out the operation. Many of the processes outlined below are applied in other types of drilling activity, for example the drilling of a well from an operator's own production installation.

The appendix aims to illustrate that there are many forms of risk assessment required during a typical drilling operation. They vary from those that rely on the application of state-of-the-art computation models (eg fire and blast analysis) to those carried out within the context of a job specific risk assessment or toolbox talk.

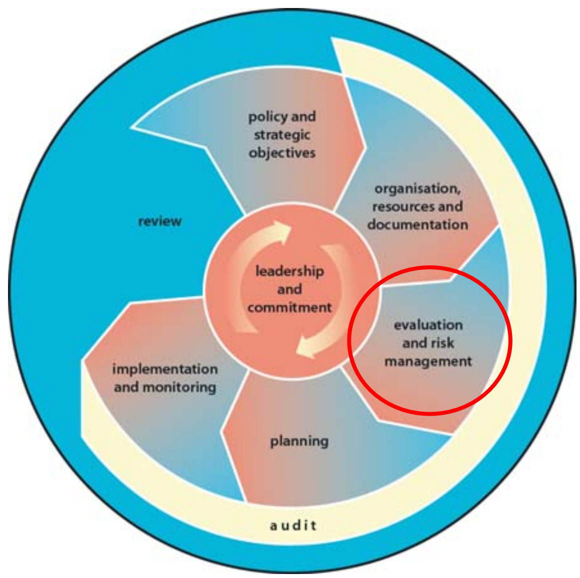
Risk assessment activities within the UK sector are, to an extent, influenced by the requirements of the regulatory regime. The regulatory process dictates that certain rig

[5] An exploration well is chosen as it incorporates a wider spectrum of risk assessment activities than many other types of well.

and site specific risk assessments be undertaken and documented in the form of a Safety Case, Environmental Impact Assessment and Oil Spill Response Plans. Section 9 provides an overview of the relevant aspects of the regulatory regime and the requirements it imposes on drilling operations.

2. Overview of the Risk Management Process

Risk assessment is an integral part of the risk management process, which is in itself an integral part of an organisation's HSE-Management System.



Risk assessment encompasses the identification of the hazards that may arise during an activity, and the assessment of the probability that certain consequences may result.

There are many different types of risk assessment undertaken during a typical E&P operation. Some require the input from technical specialists using highly sophisticated computational models or industry recognised failure rate data, other will rely on the competence of the individual(s) performing a specific activity. A key requirement within any HSE-MS is that an appropriate form of risk assessment is undertaken which is commensurate with the nature of the risk being managed.

2.1 Risk Matrix

The risk assessment process results in the identification of a large variety of risks, each having its own mix of probabilities and consequences. A tool frequently adopted by E&P companies to determine the action required with respects to each risk, is the Risk Matrix (Ref: Figure 1).

The Risk Matrix can be applied to different risk types including:

- Injury to personnel (safety)
- Damage to the environment
- Damage to the asset
- Company reputation

Each risk when plotted on the matrix falls into one of three categories:

- Red Zone: the risk level is such that the operation is deemed to be too risky and additional risk reduction measures need to be applied.
- Yellow Zone: Within this zone the risk needs to be managed to a level that is as low as reasonably practicable (in line with the UK regulatory requirement)
- Green Zone: risks within this zone are viewed as being sufficiently low as not to warrant a major effort to identify risk reduction measures. Continuous improvement in risk management is, where practicable, delivered within this zone.

In practice, the uncertainties inherent in the risk assessment process results in the risks being shown on the matrix as areas rather than individual points. In addition, the recognition that a given hazard can result in a range of consequences and associated probabilities, further complicates the use of the matrix.

CONSEQUENCE					**PROBABILITY**			
Severity	**People**	**Assets**	**Environ**	**Reputation**	**A** Rare	**B** Unlikely	**C** Probable	**D** Likely
0	Zero Injury	Zero Damage	Zero Effect	Zero Impact	**CONTINOUS IMPROVEMENT**			
1	Slight Injury	Slight Damage	Slight Effect	Slight Impact				
2	Minor Injury	Minor Damage	Minor Effect	Limited Impact				
3	Major Injury	Local Damage	Local Effect	Considerable Impact		**ALARP ZONE**		
4	Single Fatality	Major Damage	Major Effect	Major National Impact			**INTOLERABLE**	
5	Multiple Fatalities	Extensive Damage	Extensive Effect	Major International Impact				

Figure 1: Typical (simplified) Risk Assessment Matrix

Implicit within the use of the matrix is the concept of *risk acceptance*. While there are differences within E&P companies with respects to the range of consequences and probabilities addressed within the matrix, and the boundaries at which changes in the risk profile occur, their matrices are broadly similar. For example, all organisations view the risk that an activity will result in an individual having a probability of greater that 10^{-3} per annum of becoming a fatality as intolerable (unacceptable).

3. Drilling Risk Assessment

An exploration drilling activity can be broken into a series of stages during which different types of risk assessments are undertaken:

- Pre-operational risk assessments and permitting activities
- Well design
- Selection of rig, equipment and services
- Pre-mobilisation
- Operation

The following sections provide a (non-exhaustive) list of types of risk assessment undertaken within each stage.

4. Pre-Process risk management

Prior to commencing a drilling operation, and as part of the regulatory permitting requirements, a range of activities are undertaken aimed at demonstrating to the E&P company and the regulators that the well can, in principle, be drilled in a manner that should not result in harm to individuals or damage to the environment.

Many of the activities carried out during this stage will not rely on detailed knowledge of the MODU or associated support systems (which, at this early stage, may not have been contracted).

Activities that rely on the outcome of some form of risk assessment include the development of:

- Environmental Impact Assessment and Environmental Statement
- Oil spill response, blowout and relief well plans
- High level risk register (and associated risk management plan)

4.1 Environmental Impact Assessment

Many E&P companies will, as part of their own corporate requirements, undertake some level of environmental risk assessment (Environmental Impact Assessment, EIA) for any project with the potential to have an environmental impact.

For UK offshore drilling operations, the regulator (DECC) requires an Environmental Statement (an output from the EIA process) to be produced in advance of commencing the drilling operation[6]. The ES is reviewed by the regulator and a number of government agencies prior to the E&P company being given the approval to drill the well.

The level of detail contained within the EIA, and the site specific information that needs to be collected to support its production, is related to the environmental sensitivity in the region of the well to be drilled.

A typical EIA will include an assessment of the risks associated with:

- Accidental spills (hydrocarbon and chemicals) including blowout potential
- Disposal of drill cutting
- Damage to sensitive environments (eg due to mooring lines and anchors)
- Disturbance to marine life and birds
- Sound being introduced into the water column and its effects on marine life
- Impact on fishing

These different types of risk assessments will draw on information from site specific investigations, modelling, similar, past operations and failure rate data in order to determine appropriate probability and consequence values to apply within the context of the Risk Matrix.

4.2 Oil Spill Risk Assessment Activities

Irrespective of the likelihood of a blowout occurring, UK regulations require E&P companies to model a range of potential blowout scenarios and assess the risk of hydrocarbons impacting (for example) sensitive areas. This type of risk assessment requires the use of sophisticated computational models, capable of modelling the propagation and fate of hydrocarbon products over prolonged durations and in a range of (statistically realisable) metocean conditions. An output from this type of modelling will be 'risk contours' which indicate the likelihood of a certain concentration of hydrocarbons arriving at a particular location. This information will (for example) allow the operator to determine what type of oil spill response equipment may be required to respond to different levels of spill.

[6] For 'low risk' wells being drilled in 'non sensitive' areas, an ES may not be required.

4.3 High Level Risk Register

As part of its own internal assurance processes, an E&P company will normally produce a high level risk register which documents the main HSE specific risks associated with the planned drilling activity. This information will be used in developing the project specific HSE management plan and may influence the selection of the MODU, equipment and supporting services.

5. Well Design

An exploration well is designed to manage the uncertainty in the true nature of the well to be drilled. The possibility of shallow gas, uncertainty in pore-pressure and temperature, porous and permeable intervals, weak formations etc all need to be assessed, and the well design and drilling programme developed to cater for 'worse-case' scenarios.

Offset well data, computation modelling and site specific survey data allow the geoscientists to provide the drilling engineers with information on the likely range (probabilistic) and maximum values of key design parameters. The drilling engineer designs the well (and the associated drilling programme) on the basis of maximum anticipated values.

Explicit risk assessment, in terms of assigning quantitative probabilities of failure to all parts of the well design, does not feature in the design of a typical exploration well. However risk assessment is implicit within the design process, specifically through the adoption of E&P company manuals and procedures and industry recognised design approaches.

Independent review (both within the E&P company and by the Independent Well Examiner) provides further assurance that the key risks have been identified and are being appropriately managed.

Fundamental to the control of drilling related (down-hole) risks is the ability to detect, risk assess and respond to deviations out with the expected drilling parameters.

6. Selection of Equipment, Systems and People

6.1 Assessing the ability of the MODU to perform the required operation

The water depth, environmental conditions, reservoir and geophysical properties will dictate the type of rig and equipment required to perform the drilling operation.

Highly technical risk assessments will be undertaken both to demonstrate that the rig is capable of providing an acceptable working environment, and to determine the limits to which certain operations will be undertaken.

During this phase, the ability of the equipment and systems on the rig to provide a suitable barrier(s) to well control incidents will be reviewed (eg pressure rating and functionality of the BOP).

The ability of a MODU to operate at the specific location will be assessed, usually through the application of an industry recognised site assessment practice (eg SNAME 5-5A Guidelines for the Site Specific Assessment of Mobile Jack-Up Units). The objective being to ensure that the risk of (for example) a structural or mooring failure does not exceed the company's and regulator's (risk acceptance) requirements.

The risk assessment process is, to an extent, embodied within the relevant design and assessment standards applicable to the particular type of MODU. However, detailed, site-specific risk assessments support the application of these standards, for example the analysis of borehole data to establish the risk of a punch-through.

Where a MODU is deemed to be operating close to the limits of its operating envelope, more detailed risk assessments may be undertaken. These may require the use of appropriate metocean criteria and structural response models.

6.2 Major Incident Risk Assessment

How major incident risks are managed by the drilling contractor on the MODU is of interest to both the E&P company contracting the rig and the UK regulator. UK regulations require the drilling rig operator (Duty Holder) to produce a Safety Case for the rig that (amongst other things) demonstrates that all major incident risks have been assessed and suitable controls put in place to reduce the risks to as low as reasonably practicable (ALARP).

The Safety Case is used to demonstrate that the risk to an individual worker is as low as reasonably practicable. Typically this is demonstrated through the analysis and summation of all the individual risks and how they impact different classes of offshore personnel.

The major incident risks for which some level of risk assessment is undertaken normally include:

- Hydrocarbon releases resulting in fires, explosions or asphyxiation
- Structural failure (environmental overload, foundation failure, seismic etc)

- Mooring failure (loss of station keeping and secondary impacts)
- Ship Collision
- Helicopter operations
- Lifting operations and dropped objects (with major incident potential)

The nature of the risk assessment exercise undertaken for each of the risk types varies from analysis of past incident data, to the detailed assessment of blast overpressure resulting from hydrocarbon releases of varying sizes and from different locations.

6.3 Selection of Support Services

All drilling operations require some level of 3rd party support which typically includes: helicopter operations, standby and supply vessels, 3rd party services and equipment on the rig, onshore supply base and so on. Associated with each of these activities some level of risk assessment will be undertaken (normally by the E&P company). These risk assessments will, for example, drive the need to develop ‘bridging arrangements’ between the contractors that contribute to the management of a particular activity and the risks that arise from it.

7. Pre-mobilisation activities

7.1 HAZID/ENVID Meetings

HAZID/ENVID meetings form part of a structured approach to identifying safety and environmental hazards and the risks they pose. HAZIDs focuses on safety related risks, while ENVIDs on environmental risks.

Where possible they involve all the key parties that may have a role to play in identifying, assessing, accepting and managing the risks identified. A drilling HAZID/ENVID meeting will typically include the involvement of the E&P company, drilling contractor and drilling service companies, and it is often facilitated by an expert in the use of HAZID/ENVID processes.

Risk assessment within the HAZID/ENVID process takes many forms, ranging from the experience of the individuals present to determine an appropriate risk level (and any additional risk controls required) to passing the a ‘risk’ on to a specialist contractor to assess in detail.

Perhaps the most important aspect of this process is the identification of hazards through the experience and knowledge of all the parties engaged, and the identification of those areas where further effort is required to manage the risk to an acceptable level.

7.2 Drill a Well on Paper (DWOP) and related activities

A DWOP meeting takes place shortly before the drilling operation commences. It engages key individuals involved in the planning and delivery of the well. Its focus is on analysing the proposed drilling operation in detail with those individuals who will be carrying it out (or are indirectly involved).

By this stage of the process it is expected that the more technical risk assessments activities will have been undertaken, however the DWOP represents the opportunity for the parties involved in each operation to ensure that they have fully appreciated the operation and their role in it, are able to deliver the required performance and where necessary are able to identify further risk reduction measures.

Similar process are used to address the completion and testing phases of a drilling operation.

7.3 Well Specific Operating Guidelines (WSOG)

WSOGs are the output from risk assessments exercises which may be rig specific or specific to the operation being undertaken.

The WSOG will, for example, require certain operations to be suspended when a semi-submersible's motions (heave in particular) exceeds a pre-determined value. That value is based on a detailed analysis of how the semi-submersible will respond in varying environmental conditions, what effect those responses will have on, for example, the drilling riser loads, and what is an acceptable probability (given the seastate during which drilling continues) that a particular seastate will be experienced which overloads the riser.

While the WSOG may be little more that a single sheet indicating the limits at which certain actions are taken, it is supported by a considerable volume of detailed technical risk assessment.

Considerable expertise and access to fit-for-purpose structural and response models are required to carrying out these types of risk assessment.

8. Process risk management

During the drilling operation itself, a range of risk assessment and management activities are undertaken on a daily basis.

As each section of the well is drilled, the programme is reviewed and a confirmed to be appropriate given the conditions experienced to date.

Many activities are undertaken within the bounds of a risk assessment activity carried out some time earlier (eg through the development of WSOG).

Many maintenance activities, whether directly or indirectly related to the drilling programme, will require some form of risk assessment to be undertaken, commensurate with the type of risks the activities presents. Certain types of activity (eg work on electrical systems or entry into confined spaces) will be controlled through the Permit to Work System, embedded within which is the requirement for some form of risk assessment to be undertaken and signed off by an appropriate level of management.

8.1 Management of Change

A Management of Change process is a key process with any HSE-Management System. It will include a requirement to consider whether the change (proposed or actual) will affect the risk profile, and what, if any, additional risk control measures need to be put in place. For the majority of changes (specifically where an urgent decision is not required) an appropriate level of risk assessment can be undertaken to support the decision to proceed with the change.

The extent to which personnel on the rig will be authorised to deviate from the drilling programme without consulting the shore will vary depending on the nature of the deviation and the desire of the E&P company (and rig owner) to be involved in the decision making process. Normally the E&P company's expectations in this area are communicated through pre-agreed 'bridging arrangements' and operationally through the drilling supervisor.

8.2 Working Beyond the Limits of Existing Risk Assessments

The nature of exploration drilling is such that, on occasion, urgent decisions will need to be taken concerning whether to proceed on a particular course of action. The WSOG and other documents will have assessed a range of potential scenarios and identified the procedure required to manage the risk should one of those scenarios arise. However, there will arise situations where a risk management decision will need to be taken for which an existing risk assessment is unavailable.

In such situations reliance is placed on the competence and skills of the rig based personnel to carry out some level of risk assessment to determine an appropriate course of action. Where time allows, land based expertise can be accessed to support the decision making process.

Ultimately the decision rests with the OIM, who needs to be comfortable that the proposed course of action does not compromise the safety of personnel on the rig (as a priority) or lead to some level of damage to the environment.

9. The UK Regulatory Framework

Different UK government departments are responsible for the management of safety and environmental risks. The UK Health and Safety Executive (UK HSE) through its Safety Case and supporting regulations, leads on the management of risks that can result in death or injury, while the Department of Energy and Climate Change (DECC) takes the lead on environmental risk management.

UK Safety Case Regulations (SCR) requires the Duty Holder to identify, assess and manage all major incident risks, including:

- A fire, explosion or release of a dangerous substance involving death or serious personal injury to persons on the installation or engaged in an activity on or in connection with it.
- An event involving major damage to the structure of the installation or plant affixed thereto or any loss on the stability of the installation.
- Any other event arising from a work activity involving death or serious personal injury to five or more persons on the installation or engaged in an activity in connection with it.

The Duty Holder is defined as either the operator of a production operation, or the owner of a non-production operation. In the case of a MODU, the rig owner is normally the Duty Holder.

9.1 Independent Verification and Well Examination

UK offshore regulations[7] establishes two processes through which independent and competent bodies become part of the risk management process. One process relates

[7] The Offshore Installations (Safety Case) Regulations 2005 and the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996.

to safety critical elements associated with the MODU itself, the other relates to the well. There is an area of overlap between the two processes (not discussed further here).

9.2 Independent Verification of Safety Critical Element

The Safety Case Regulations require the Duty Holder to identify any parts of the MODU (including computer software) the failure of which may cause or contribute substantially to a major accident, or the purpose of which is to prevent or limit the effect of a major accident. These items are termed Safety Critical Elements (SCEs).

The regulations require the Duty Holder to put in place a scheme for the verification of the choice and ongoing effectiveness of the SCEs. Hence, for example, the ability of a semi-submersible to withstand extreme metocean conditions would need to be verified by an independent and competent body or person (ICB or ICP).

9.3 Well Verification Scheme

The Design and Construction Regulations requires the well-operator (normally the E&P company) to ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned such that:

- So far as is reasonably practicable, there can be no unplanned escape of fluids from the wells;
- Risks to the health and safety of persons from it or anything in it, or strata to which it is connected, are as low as is reasonably practicable.

The regulations go on to require the well-operator to document and put in place a system for the examination by an independent and competent person (the well examiner) of the design, operation and maintenance of a well. The expectation of the regulations is that the well examiner becomes an integral part of the process through which the above objectives are met.

9.4 Verification, Examination and Risk Assessment

The verification and examination processes draw on what should be the broad experience of the independent and competent bodies to identify areas where the Duty Holder's or Well Operator's own processes may have failed to deliver fit-for-purpose solutions. Some level of secondary risk assessment is implied within this process. It may be that the ICB does little more than confirm that the analysis carried out by the Duty Holder is acceptable (eg by acknowledging that the application of a particular design standard is appropriate), or the ICB may carryout its own risk assessment (eg where it may wish to confirm that the hydrocarbon release frequencies, used in deriving individual risk levels, are appropriate).

The verification and examination processes required through UK legislation do not replace the need for the Duty Holder or Well Operator to have in place its own quality assurance and control processes.

Post Workshop Addendum with Findings and Recommendations

This Addendum was added after the Workshop to record the Findings and Recommendations that were discussed at the Risk Assessment breakout session. There were seventeen participants in the discussion representing BSEE, industry operators, service companies, contractors, and the Department of Energy.

One of the first discussion points surrounded the fact that Risk Assessment in general is a very broad topic and perhaps too difficult to cover in a general session. As a result, the discussion did not cover all the areas in the original white paper. Nevertheless we did manage to identify some specific findings of general agreement for both the industry and the regulators in this area. In this Addendum we will cover both generally agreed upon findings as well as highlight some important discussion topics that did not necessarily resolve themselves into recommendations.

It was widely recognized that as a result of the Macondo accident, the regulatory body (BSEE) received a considerable amount of external criticism that they were "too close" to the industry. In response to this criticism, communication channels have been significantly reduced. The general consensus of this group was that more communication, not less, between regulator and industry would be highly beneficial. There is a high level of respect between industry and regulator (on both sides); both regulators and industry have contributions to make toward improving safety; and combined efforts are a significant improvement over working in isolation.

Recommendation #1 (for BSEE)

a) The regulator should explore methods of establishing a more *collaborative* approach to working with industry. Dialog between regulators and industry is important to encourage continuous improvement and development of a safety culture.
b) Time frame – Immediate
c) Priority – High.

Each of the industry operator and service company representatives in this discussion noted that their own companies had significant process risk management programs that were (at least internally) considered to be largely effective. It was recognized that these programs can and should always be improved. Even more important than improving any particular risk methodology however was the importance of communicating the risks discovered to the workers in the field. There was a strong group sentiment that developing processes and technology for effectively communicating and making risk understandable is currently more important than improving the assessment methodologies.

Recommendation #2 (for BSEE)

a) Encourage (possibly anonymous) reporting of “near misses” (perhaps similar to FAA voluntary program)
   -- Focus should be on identifying trends or patterns to aid in identification of potential hazards, root causes and mitigating factors
b) -- Focus on process safety and well integrity
   -- Need to develop clear definition of what should be reported
c) Time Frame – Short term
d) Priority – High

The previous recommendation highlights another problem around incident data collection where it has been recognized that due to the non-uniformity of collected incident data, all the data currently needs to be sorted, categorized, and analyzed manually – a time consuming and error prone process. Now is the time to utilize the incident database to help standardize the incident reporting data format and transition it to an automated, computer “friendly” data input process.

Recommendation #3 (for Industry)

a) Industry should work on establishing a process for effectively communicating results of risk assessments to the workforce
   -- The goal is to identify and mitigate hazards (not “check the box”)
   -- Communication is more important than developing new tools
   -- Need to establish/improve mechanisms to share lessons learned from previous events
   -- Risk assessment results and lessons learned need to be disseminated in an understandable fashion.
   --The workforce needs to understand cause and effect (“why” as well as “what”)
b) Time frame – Short term.
c) Priority – High.

One of the few IADC/API documents that provides specific guidelines for risk assessment is API 14J. Although 14J is specific for offshore production facilities and has not been updated since 2002 it forms a good baseline from which to build and expand. This document was seen as a good starting point for incorporating the latest risk assessment technology and upgrading risk practices across the industry.

Recommendation #4 (for Industry)

a) IADC/API should review risk assessment methodologies using ISO documents as references to update API 14J, which offers guidelines for risk assessment.

-- Develop recommended practice (similar to methodology of API 14J) that focuses on risk assessment of escape and evacuation from offshore platforms and rigs
-- Need to consider overall risk assessment for integrated production facilities to address interaction between downhole, surface systems, topsides of all structures/vessels involved
-- Need to consider risk assessment of simultaneous operations between platforms, MODUs, and marine vessels

b) Time Frame – Short term to get started
c) Priority -- Medium

Although the BSEE organization (and its predecessors) requires reports to be filed for offshore “incidents” there is no such data gathering for “near misses”. Comparative analysis from other industries has largely demonstrated that “near misses” follow many of the same precursors that lead to incidents and a proper analysis to this data would be highly beneficial for reducing the number of incidents. For this to occur, a number of issues surrounding the reporting details (e.g. which data should be reported; what formats should be used; how it should be collected; how should proprietary issues be managed) would need to be resolved, and some data gathering experience would be highly beneficial in resolving these. While there was not yet a consensus among the group, valuable areas to consider should include “kicks” -- specifically kick frequencies, kick volumes, and kick intensity. Consideration for existing efforts such as the OGP WEC database should also be taken into account. As a first step toward beginning this process the recommendation is not to immediately mandate a solution, but work toward building a collaborative solution with the industry.

Recommendation #5 (for BSEE)

a) Develop or adopt a standardized reporting system to facilitate computer sorting/analysis of incident data.
   -- Current system requires manual sorting/categorization of incident reports
   -- Perform a study to clearly define the data that needs to be collected and means of reporting
   -- Commercially available systems may be preferable to brand new systems
   -- Evaluation/analysis of data should be made available as feedback to industry
b) Time frame – Short term to get started
c) Priority -- High

It was recognized that exercises where multiple companies apply their capabilities in risk management to the same problem are highly beneficial for both the regulator and the industry. Such studies not only demonstrate the state of the art in risk assessment, but can also serve to define agreed upon baselines for further developing and understanding risk assessments.

Recommendation #6 (for BSEE)

a) BSEE should consider commissioning one or more simulated scenario-based risk assessments conducted by third party (similar to DNV exercise commissioned by Norwegian Oil Association OLF).
   Possible scenarios include a hydrocarbon release from a deepwater floating rig, or an analysis of a new technology implementation.
b) Time Frame – Short term to get started
c) Priority -- Medium

Another important discussion involved the use of Reliability Based Design (RBD) as a strategy for moving beyond current well design strategies based on limit state design. While there was not a formal recommendation, there was a strong sentiment from the group that Reliability Based Design is a widely recognized approach for mechanical design (including well design) and should be encouraged.

Speaker and Steering Committee Bios

Ken Armagost

Ken Armagost is a Project Drilling Advisor for Anadarko Petroleum Corporation in Houston, Texas. He has 32 years of domestic and international experience including onshore, shelf and deepwater drilling operations. He has also worked in the development of drilling and intervention technologies including large-bore and low-cost rotary steerable systems, managed pressure and dual gradient drilling, casing drilling, wellbore strengthening, and in the development of a rig assisted hydraulic workover system for deepwater floating interventions. He holds a BS degree in Chemical Engineering from Ohio State University.

Joseph C. Braun

Dr. Braun is a Nuclear Engineer at the Argonne National Laboratory with over 40 years of experience in engineering and management. He is currently involved with ANL activities to support the USNRC in the licensing of advanced nuclear reactors. He is also developing training courses for the International Atomic Energy Agency (IAEA) on reactor safety and licensing, with an emphasis on nuclear fuel, Management Systems, and Probabilistic Safety Analyses.

Previously, he worked for the Westinghouse Bettis Atomic Power Laboratory on the development and use of naval nuclear propulsion plants, and for Combustion Engineering Inc. on the design and operation of civilian nuclear power plants. In 1990 and 1991 he served as Executive Director of the American Nuclear Society. He has a BS and MS in Physics, and a Ph.D in Nuclear Science and Engineering.

Michael (Mik) Else

Senior Safety Research Engineer, U.S. Dept. of Interior, Bureau of Safety & Environmental Enforcement (BSEE). Mr. Else holds a Bachelor of Science degree in Petroleum Engineering from the University of Montana - School of Mines and Technical Science, May 1983. Having served eight (8) years in private industry, beginning with Getty/Texaco in 1983, Mr. Else joined BSEE's Pacific Regional office in June of 1991 to assist the regulatory oversight of offshore O&G field operations. In October of 2002, Mr. Else transferred to the agency's headquarters in Herndon, VA where he now serves as Senior Safety Research Engineer; providing oversight of the agency's Safety Research Program and various individual research efforts involving offshore energy E&P and infrastructure operations.

Dan Fraser

Dan is a Principal Architect at Argonne National Laboratory and a Senior Fellow at the Computation Institute of the University of Chicago with over 20 years of combined scientific, engineering and risk management experience. As a scientist at the Los Alamos National Laboratory he worked on the risk assessment of complex systems with extreme safety implications. He later became a Principal Engineer with NEC, Sun Microsystems and Paremus Ltd. where he learned to apply (Six Sigma) performance based metrics in design, analysis, and risk management to a variety of applications in different industries including oil & gas.

Frank Gallander

Intervention Consultant, Chevron Upstream Gas (Drilling & Completion Operations)
35 Years in Industry, 30 Years with Chevron
Global support in commissioning, maintenance and field operations of BOP / Control Systems and Well Interventions and oversight of Subsea BOP Reliability Performance.

- Chairman of API Standard 53
- Support other API and industry studies, standards and recommended practices
- Provide global support for drilling operations on complex wells & new build rigs
- Consultations for in-house BOP / Control Systems related issues
- Develop intervention programs for Deepwater wells

Tony Hogg

Tony Hogg is the Director of Subsea Engineering for Ensco. Tony has more than thirty years experience in the international subsea BOPE arena since leaving the deep coal mining industry in England, where he had served a four year indentured mechanical apprenticeship. He joined Ensco, with the acquisition of Pride International in 1999, while serving as Senior Subsea Project Engineer for an affiliate designing and building the Amethyst class rigs. Tony is a member of SPE, of various JITFs and is currently active on the API S53 committee. He is scheduled to chair the impending rewrite of API RP 64.

Holly Hopkins

Holly Hopkins is a senior policy advisor in Upstream and Industry Operations of the American Petroleum Institute (API). In her current role with API, she staffs the Drilling and Production Operations Subcommittee, the Oil Shale Subcommittee and two of the four Joint Industry Task Forces, the Offshore Equipment Task Force and the Subsea Well Control and Containment Task Force.

Prior to joining API Holly was a policy consultant to the Consumer Energy Alliance (CEA), providing expert advice and guidance to CEA members regarding the Executive Branch.

From August 2001 to January 2009 Holly worked for the US Department of the Interior in several capacities. Most recently she served as the Chief of Staff to the Minerals Management Service (MMS) where she advised the Director and senior management on issues related to offshore energy development and federal revenue collection. Holly also served as MMS Liaison to the Assistant Secretary, Land and Minerals Management and as Special Assistant to the Deputy Secretary. Prior to working for the Interior Department she worked as a policy assistant at National Environmental Strategies.

Steve Kropla

Steve Kropla is Group Vice President - Operations and Accreditation for the International Association of Drilling Contractors. He is responsible for managing and directing the operations of the association's Offshore Division, Land Division, Drilling Services Division, and Accreditation and Certification functions as well as regional operations in North America, Europe, the Middle East, Africa and Asia. He is also responsible for overall management of IADC's technical and professional service committees.

In addition, Mr. Kropla is currently participating in OGP's Wells Expert Committee, where he is co-chair of the Human Factors, Training & Competence Task Force and a member of the BOP Reliability & Technology Task Force. He is also a member of the planning committee for an "Effects of Deep Water" workshop to be held in November which is being developed by the US Bureau of Ocean Energy Management, Regulation and Enforcement in conjunction with Argonne National Laboratory. In the wake of the Macondo incident last year, Mr. Kropla presented testimony for investigations conducted by the National Academy of Engineering and the National Commission on the BP Deepwater Horizon Oil Spill and the Future of Deepwater Drilling. Much of this testimony focused on *the IADC HSE Case Guidelines for Mobile Offshore Units*.

Previously, Mr. Kropla served as IADC's Director and later Vice President of Accreditation & Certification Programs. In this capacity, he was responsible for developing and ongoing administration of accreditation systems for the evaluation and recognition of industry training providers: these include the IADC Well Control Accreditation Program or *WellCAP*®; the *RIG PASS*® safety orientation program, Ballast Control & Stability accreditation & certification, and Competence Assurance Accreditation. He also functioned as the key staff liaison for the development of the *IADC Deepwater Well Control Guidelines*, which was awarded a Special Commendation by the Offshore Technology Conference.

Mr. Kropla joined IADC in 1992 after more than 10 years experience in the drilling industry in Alaska, the lower 48 US states and involvement with international operations in Southeast Asia, South America, Europe and the Middle East. His duties included overall management for health and safety, training, and responsibility for a broad range of human resources issues. He holds a BS degree from Southern Illinois University and a MS degree in Human Resources Management & Development from Chapman University in Orange, California. Mr. Kropla is a Certified Senior Professional in Human Resources.

David Miller

David Miller is the Director of the Standards Program for the American Petroleum Institute, or API . In this role he is responsible for overall standards policy and implementation and is a member of API's Senior Management Staff. He is an acknowledged standards expert and has testified before the U.S. Congress, Federal and State regulators on standards and technology issues.

David is also active in international standards activities, serving as Chairman of the American National Standards Institute, or ANSI International Policy Committee and on the ANSI Board of Directors. He also represents API on the U.S. Department of Commerce Industry Trade Advisory Committee on Standards and Technical Barriers to Trade, and is a member of the Offshore Technology Conference Board of Directors.

David is a registered professional engineer and earned a Bachelor of Science degree in Civil Engineering from the University of Utah and a Master of Science degree in Environmental Sciences from the University of Texas at Dallas. He joined API in 1985 and was elected a Fellow by the American Society of Civil Engineers in 2006, and received an ANSI Meritorious Service Award in 2007.

James B. Raney

Jim Raney graduated from the United States Military Academy at West Point in 1975. Jim joined Mobil Oil in 1981. He served in a variety of technical and management assignments with Mobil and ExxonMobil before joining Anadarko Petroleum in 2001. He was called to active duty to support Operation Enduring and Iraqi Freedom. In 2004, Jim Raney returned to Anadarko and is currently in the Director, Engineering & Technology. In addition, Jim severs as Chairman of the API Committee on Standardization of Oilfield Equipment and Materials (CSOEM).

Kumkum Ray

Kumkum Ray is a Senior Regulatory Specialist at BSEE headquarters in Herndon. She holds a Master of Science degree in Geological Sciences from the University of Wisconsin, Milwaukee. After working for eight years as a petroleum geologist in the Gulf of Mexico Region Resource Evaluation office in New Orleans, she moved to HQ in Herndon, Va in 1989 and has worked in the regulatory arena since then. Rules she has published include: Reorganization of Title 30: Bureaus of Safety and Environmental

Enforcement and Ocean Energy Management Final Rule 2011; 30 CFR 250 Subpart B –Plans and Information Final Rule 2005; 30 CFR 250 Subpart A – Postlease Operations Safety Final Rule 1999; and 30 CFR 251, Geological and Geophysical (G&G) Explorations in the OCS Final Rule 1997.

Dan Sadenwater

Dan Sadenwater is a Subsea Intervention Team Lead for Chevron Corporation's Global Upstream Well Intervention team and is actively involved in sharing best practices across the global organization. He has a Masters degree in Business Administration from Tulane University and a Bachelor of Science degree in Mechanical Engineering from Purdue University. He began his technical career with ExxonMobil as a Subsurface Engineer and then as their Gulf of Mexico Drilling and Completions Coordinator. Later, he joined Amerada Hess as a founding member of the Global Drilling Strategic Improvement Team as its Subsea Specialist. Prior to joining Chevron, he explored the world of start-ups with a subsea intervention company that ultimately set an industry world record in 3000-feet of water.

Michael J. Saucier

Mr. Michael Saucier is currently the Regional Supervisor for District Field Operations, Bureau of Safety and Environmental Enforcement, (BSEE), Gulf of Mexico Outer Continental Shelf (OCS) Region, U.S. Department of the Interior, in New Orleans, Louisiana. As Regional Supervisor, Mr. Saucier oversees the five BSEE District Offices along the Gulf Coast who are responsible for safe and environmentally responsible oil and gas operations throughout the Gulf of Mexico OCS Region.

Mr. Saucier began his career with the Federal government in 1984 as a Staff Engineer in the MMS Houma District Office. He has held several engineer and supervisory positions in his 27 year career, most recently as Regional Supervisor for Field Operations Office with BOEMRE.

Mr. Saucier received a BS Degree in Petroleum Engineering from Louisiana State University in May 1984.

Brian Skeels

Brian Skeels is the Emerging Technologies Director of FMC Technologies, Inc. Brian has over 32 years experience in subsea completion and pipeline design and installation. 5 Years with Exxon Production Research Company working on Exxon's famous SPS and UMC subsea systems, and the rest with FMC Technologies. As FMC's Emerging Technology Director, he serves as a technical subsea advisor and strategic planning specialist for frontier technologies and new business opportunities. He is currently working on HPHT, light well intervention, ROV and remote robotics technology, and subsea spill containment programs FMC's global development activities worldwide, and technical lead for next generation ROV and deepwater intervention hardware with Schilling Robotics. Brian also chairs two API subsea task groups: for subsea equipment, and intervention systems, and serves on six others for systems, TFL equipment, ROV interfaces, HIPPS, spill containment hardware, and operation and. testing of subsea safety systems.

Alan Summers

Alan Summers is the Director of the Subsea Department of Diamond Offshore Drilling, Inc. Alan joined Diamond Offshore Drilling in 1996 and started working offshore moving up positions from Roughneck up to Toolpusher. He has over fifteen years of hands-on supervisory drilling experience both on offshore drilling rigs and in management positions. Alan's drilling experience has included working in the US Gulf of Mexico and other regions around the world including the North Sea, West Africa, Indonesia, Malaysia, and other areas. He has engineering experience as a rig engineer; working projects in the US Gulf of Mexico, West Africa, Indonesia, and Malaysia. Alan's management experience includes onshore rig management of jackups drilling rigs up to 5th generation floating drilling rigs and managing the DODI's Subsea department worldwide.

Charlie Williams

C.R. (Charlie) Williams II is Chief Scientist - Well Engineering and Production Technology for Shell worldwide. He has worked for Shell for 39 years in many different R&D, engineering, and operations management assignments including VP of Global R&D. Charlie has been working extensively on post-Macondo industry response including serving as advisor to Shell senior management. He currently chairs two Industry Task Forces - Subsea Well Control & Containment and API - Center for Offshore Safety, as well as being Chairman of the Governing Board for Center for Offshore Safety. He also serves on the DOI OESC Federal Advisory Committee, the Operating Committee of the Marine Well Containment Project, and on the Executive Board of the Marine Well Containment Company. He continues to testify at numerous Commissions including the Presidential Commission and the National Academy Commission. He presented at the recent panel "Root Causes of Incidents and Responses" at the National Conference on Science, Policy and the Environment and on drilling & drilling safety management at the Center for Strategic and International Studies. Charlie is a member of the API Committee on Standardization of Oilfield Equipment and Materials and the US Tag to ISO TC 67. He is member of the curriculum advisory committee for Petroleum Engineering at University of Texas and is an Honored Guest Professor at two Universities in China.

David Young

David Young has over 33 years of drilling and completions engineering and operations experience with Chevron. He has extensive deepwater experience in the US Gulf of Mexico, Brazil, Nigeria, Equatorial Guinea, Angola, Indonesia, and the Caspian Sea. He is a member of Chevron's worldwide blowout response team. He is a former Chevron well control instructor and member of Chevron's well control advisory committee. He served on the API Joint Industry Task Force on Deepwater Procedures that made recommendations to the DOI. He is a 1979 LSU BSME graduate.

Effects of Water Depth Workshop

Galveston, Texas
November 2-3, 2011

List of Attendees

Name	Organization
Achee, Tim	Chevron
Angelico, Eileen	BSEE
Arceneaux, Mark A	Stone Energy
Armagost, W Kenneth	Anadarko Petroleum Corporation
Arnold, Ken	WorleyParsons
Aures, Hope	ExxonMobil
Baniak, Edmund L	American Petroleum Institute
Barnett, William	C-Mar Group
Braun, Joseph C.	Argonne National Laboratory
Brazan, Craig Gerard	Stone Energy Corporation
Breaux, Mike	Chevron
Brink, Fred	BSEE
Brunjes, Jean	GE Oil & Gas
Buus, Lars	DNV USA Inc, Houston
Carbaugh, William Lyle	GE Oil&Gas
Castille, Craig T.	Stone Energy Corporation
Chapman, Bryan L	ExxonMobil Production Co.
Coco, Ben	BSEE
Corrigan, Mike	Cobalt International Energy
Cowan, Bill	ENI U.S. Operating Co.
Cowan, Bob P	National Oilwell Varco
Craig, Don	Aker Solutions
Cummings, Ricky	Chevron
Daniels, William	USCG
Daugherty, Bill	ATP Oil & Gas Corp.
DeBruijn, Gunnar	Schlumberger
Dore, Eddie	Nexen Petroleum U.S.A. INC
Dulisse, Carmine M	Marine Well Containment Company
Dupal, Kenneth	Shell
Dupriest, Fred E	ExxonMobil

Name	Organization
Dupuis, Dominique Charles	Ensco Plc
Dusterhoff, Heather L	Cobalt International Energy
Else, Mik	BSEE
Feijo, Luiz	ABS
Fett, Darryl	Cobalt International Energy
Fraser, Tom	GE Oil & Gas
Fraser, Dan	Argonne National Laboratory
Frazelle, Andrew	BP
Fury, Sandi M	Chevron
Gahr, Jason	ExxonMobil
Gallander, Frank B	Chevron Upstream Gas / D&C
Gardner, Craig Alan	Chevron
Girlinghouse, Kerry	Wildwell Control Inc
Gradishar, John	Shell
Graff, Richard Lee	Chevron
Grant, James	BP America
Harris, David C.	Anadarko Petroleum Corporation
Hogg, Tony	Ensco
Hopkins, Holly	API
Hopkins, Scott	Transoceam
Hoshman, Russell M	BSEE
Johnson, Dennis	BP
Kaiser, John	US DOI BSEE
Kakar, Karan	2H Offshore
Karlsen, Geir	BP
Kenny, Ted	Sonardyne International
Kozicz, John	Transocean
Kropla, Steve	International Association of Drilling Contractors
Labiche, Lance	BSEE
LaFreniere, Lorraine Marie	Argonne National Laboratory
Lambert, Joe	Shell
Lambert, Kevin	Hess
Lan, Christy M.	BSEE
Landeraaen, Paul	Statoil North America Inc.
Levett, Bryce	Det Norske Veritas
Lewis, David B.	Blade Energy

Name	Organization
Little, Patrick	USCG Marine Safety Center
Ljungdahl, Patrick M	Boots & Coots
Lyle, Orlan	Noble Drilling
Malstrom, Kirk	BSEE
Marcom, Mike	Rowan Drilling Company
Martin, David	ENSCO
Massey, Marty	Marine Well Containment Company
McCarroll, John E.	BSEE
Melchert, Elena Subia	U.S. Department of Energy
Miller, David	American Petroleum Institute
Miller, Charles	Marine Well Containment Company
Mohon, Bobby	ExxonMobil
Monkelien, Kyle	BSEE
Nye, Nicolette	NOIA
Osmond, Jerry	Hess Corporation
Pallini, Joe	GE Oil & Gas
Parker, Ben	Det Norske Veritas
Patel, Harish N.	American Bureau of Shipping
Payne, Mike Lyle	BP America
Pelley, Darrel	Transocean Offshore Deepwater Drilling, Inc.
Pham, Man D	ABS
Powers, Jim	ExxonMobil Development Company
Randall, Scott	PlusAlpha Risk Management Solutions, LLC
Raney, James	Anadarko Petroleum
Ray, Kumkum	BSEE
Reynolds, Joshua	USCG Headquarters
Rhome, Wilbon A	BSEE
Riddle, Gene	Repsol, Global Offshore Drilling and Completions
Rinaudo, Marty	BSEE
Rizvi, Aijaz(AJ)	Halliburton
Roach, Sean	Boots & Coots Well Control
Robins, Derek Alan	Marine Well Containment Company
Rodot, Francois	Total E&P USA
Rogers, Bryan	BSEE
Rohloff, Greg	BP

Name	Organization
Ruddy, Kenneth	Cobalt International Energy
Sadenwater, Daniel T	Chevron Upstream & Gas
Sattler, Jeff	WEST Engineering Services
Saucier, Michael	BSEE
Savoy, Joe L.	Wild Well Control, Inc.
Shanks, Forrest Earl	Oceaneering International, Inc.
Singh, Gurinder	American Bureau of Shipping
Sivley, Robert S	Hunting Energy Services
Skeels, Brian	FMC Technologies
Skinner, Les	Shell E&P
Smith, Phil	Shell Upstream Americas
Soliah, James	Delmar Systems Inc.
Springett, Frank	National Oilwell Varco
Stawaisz, Raymond	Chevron
Stein, Kurt	DOI/BSEE
Stoltz, Dan	Newfield Exploration
Summers, Alan	Diamond Offshore Drilling Inc.
Surgnier, David	Argonne National Laboratory
Sweatman, Ronald	Halliburton
Trocquet, David J	BSEE
Tschritter, Gordon	Cobalt International Energy
Vinson, Barry	Sub Surface Tools, LLC
Webb, Tamara	Shell Exploration & Production Company
Welsh, Erin M	Seadrill Americas
White, Amy	BSEE
Williams, Charlie	Shell Energy Resources Co.
Wright, Brian	CAD Control Systems
Young, David	Chevron
Zaunbrecher, David	Hess Corporation