Effects of Water Depth on Offshore Equipment and Operations
Topic #3: Well Drilling & Completion Design and Barriers

General Purpose

This white paper on "Well Drilling and Completion Design and Barriers" is one of six papers that will be 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 white paper is meant to provide a brief background on the topic and identify 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)

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

The topic of Session #3 is the design of deepwater drilling and completion programs (including wells utilizing subsea wellhead/BOP systems and those wells utilizing surface wellheads/BOPs that are drilled and completed from floating facilities such as spars or TLPs), the implementation of these programs (the well construction process), and the validation and monitoring of the barrier system during the well construction process.

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 are intended as topics of focus for the workshop discussions.

This white paper will be issued prior to the workshop as a draft document. It will be further developed based on discussions during the workshop with the final version issued following the workshop.

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

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Introduction

Life cycle 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. Beyond strength, all of the structural components must possess the metallurgical properties required to provide reliable service in the installed environment. Foundational to these requirements are the recognized standards for equipment design and manufacture and the associated QA/QC programs that support the integrity of the equipment, tools, tubular goods, barriers, and materials used to construct the well.

Well Design

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, chlorides, 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, and 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.

Additionally, well design is constrained 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 must often be run 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 (note: the 'worst case discharge' design basis, that affects collapse pressure requirements, has reduced the shallow applications for expandable casing technology), and managed pressure drilling (MPD) technologies (such as continuous circulation systems, ECD reduction devices, and dual gradient drilling).

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 must then be centralized within the enlarged hole sections to provide the uniform clearance within the annulus in preparation for cementing operations.

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 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 during drilling and non-drilling operations (with riser connected) are considered, particularly with regard to potential damage to the wellhead system as a result of drift-off or drive-off (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
- an enhanced 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 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 and ensure adequate as welded wall thickness

Casing Design

Regulatory requirements must be considered as casing points are identified and load cases 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 affect casing strength. Factors such as casing wear must be considered when designing casing programs.

Annular pressure build-up (APB) associated with annular 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.[2] 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 cycle of the well. They isolate pressures and prevent unwanted movement of fluids within the wellbore and in the casing annuli. Some barriers are used temporarily to facilitate the 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 BOEMRE for all aspects of well construction.

The barriers used in well construction have been identified in API STD 65 – Part 2. They have been classified in that document 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 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 construction operation, this barrier can be achieved with a column of drilling fluid, cement spacer, liquid cement, water, packer fluid, or completion fluid. The qualities of a hydrostatic barrier, including height and density, can change with time, affecting the pressure it exerts. When cement hydrates (hardens), it loses its hydrostatic effect as it transitions from a liquid into a solidified physical barrier. Under static conditions, high density weighting material can settle from a drilling fluid or cement spacer over time, 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 period of time it is required.[3]

Mechanical barriers are designed to provide environmental isolation within the wellbore or in annular spaces. Mechanical barriers can usually be pressure tested, but it is not always practical or desirable to perform the test to the full 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."

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. These aspects include:

- Two independently tested barriers across each flow path during completion
- Proper installation, sealing and locking of casing and liners
- BOEMRE approval before displacing to a lighter fluid
- Enhanced deepwater well control training

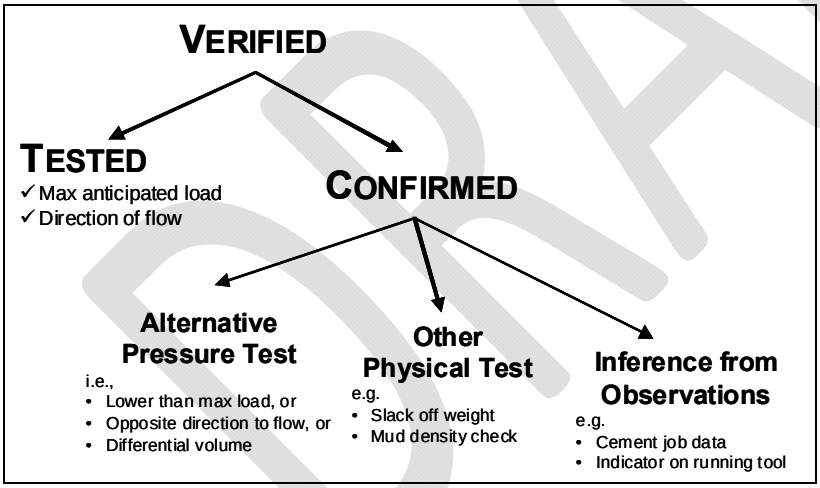

Figure 1 – Barrier Verification Categories *(from Draft API RP 96)*

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Analysis

A) Current Technologies & Challenges Implementing those Technologies

Well Design – The Technical Challenges

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

1) Worst Case Discharge Design Load

FINDING: The Worst Case Discharge design load, as currently required by the BOEMRE, is very conservative from a well control perspective. The mandated design case has resulted in well designs that add operational risk, limit design options, and that exceed operational requirements. Alternatives to this design criterion should be considered by the BOEMRE.

New regulations following the Deepwater Horizon incident have resulted in significant changes to deepwater well design. In response to the new BOEMRE 'worst case discharge' design load requirement, heavy-wall 14-inch casing is now commonly run at the bottom of intermediate strings to satisfy the elevated collapse design load. In some cases, the burst loads calculated for the upper section of this string have also required a heavier or higher strength casing design. The landing weight of these long intermediate casing strings approaches 2 million pounds in some applications. These high loads present operational challenges for many deepwater rigs.[4]

The use of heavier intermediate strings 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 are such that the casing must be set at a shallower depth. In these cases the casing program is no longer a tied to the 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 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 on trips 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. The use of 'worst case discharge' design load will make it more difficult to get the required casing size through the target interval.

The regulated use of the 'worst case discharge' (WCD) design load 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 'worst case discharge' 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 that prevented WCD and associated casing collapse).

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 to the worst case discharge. Using well established criteria for lost circulation, kick tolerance, and mud-gas gradients,

intermediate casing has been successfully designed, deployed and operated with required high reliability. For the near-term, it is recommended that historically-accepted criteria be re-established as acceptable design options by the BOEMRE.

Other less restrictive design options such as 'cap and flow' and designed deep underground relief, should also be available to designers.

Note: BOEMRE 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, BOEMRE has issued permits for wells in which the 11-7/8" liner has been designed to collapse under extreme flow conditions.

To enhance design capabilities in the longer-term, industry is working to initiate a Blowout Risk Assessment (BORA) JIP. The JIP is being formed to develop 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 and confirmed, provides advantages in many deepwater well applications. Both designs have merit and should continue to be available to well designers.

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 (note: 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 BOEMRE of these options and the current design requirement is recommended.[5]

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 wells with pressures exceeding 15 K psi at the BOP. 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.

Currently, industry faces challenges with shut-in 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 Worst Case Discharge load case, it is recommended that WCD not 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.[6] In the extreme well control case of uncontrolled flow (worst case discharge or WCD) from the reservoir, a trapped annulus can be exposed to the heat of reservoir fluids over an extended period of time. If trapped 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 of weighting material of the fluid left in the annulus over time (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 bigger more significant zone deep.

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, or rupture disks, nitrogen cushions, crushable syntactic foam, and trapped pressure compensating downhole tools to provide an accommodation space to mitigate the pressure build-up.[7] 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.

6) Working Pressure Ratings of Subsea BOP Equipment

FINDING: 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.

When working subsea, equipment designs must consider the effect of the hydrostatic pressure imposed by the seawater. This creates unique design requirements for sealing against this hydrostatic pressure which are not present for surface based equipment. Importantly, for pressure containing equipment, the seawater hydrostatic pressure acts to reinforce the structural capacity of subsea equipment. For tubulars and other equipment with relatively simple geometries, these effects can be addressed with closed form solutions. For more complex geometries, FEA or other advanced methods may be needed to fully quantify the beneficial effects of the hydrostatic column. Because the seawater hydrostatic puts a compressive hydrostatic stress state into the entire volume of the specific subsea equipment beneficial effects are seen in terms of the working stress levels for pressure containment equipment as well as general benefits for both S-N based and fracture mechanics based fatigue methods.

API is working for formalize appropriate guidance in this area. The API TR PER 15K, which is nearing completion, recommends that all salient loads, pressures, environmental effects, etc. be considered in the design verification processes. Hence, accounting for the beneficial effect of the seawater hydrostatic will be captured in that approach. This issue must be worked carefully and at a component level. For example, BOP sealing elements may not see seawater hydrostatic on the backside (i.e. downstream side), but rather be reinforced only by a hydrocarbon column from the mudline to the choke/kill manifold. Thus, the analysis of equipment performance requires detailed analysis that accurately accounts for all key operational scenarios. This is one of the guiding principles in API TR PER 15K.

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 that improve the 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 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. Regulations should be changed to require a single pressure test of this two barrier system. If the deeper barrier is successfully pressure tested, its integrity will prevent the verification of the upper barrier using a pressure test.

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 by API.[8]

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 the mechanical barrier (refer to API RP 96 draft). Field performance history is 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 in part a function of annular clearance and centralization. These attributes are particularly important in close tolerance 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.

While modern ultrasonic cement evaluation tools are more 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, based on inferences from down hole 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 for exposure to hydrocarbon bearing zones exists. 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 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.

Examples of common casing/cementing equipment include: the casing/liner itself, 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), 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 reliability of the installed casing barrier system is highly dependent on achieving the proper function of each component of the system. 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 other elements of the barrier system can be affected (i.e. by not allowing flow, pressure, or activation darts/balls, etc. to reach the proper location).

Examples of common problems experienced are: malfunctioning of the float equipment (i.e. not converting from auto-fill mode, not holding differential pressure after the cement job, etc.), float equipment and 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 these 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 the pump requirements, but additional work is required to optimize these treatments.

The WCD design load has potential to impact the size of the liner across the productive interval. If the liner size is too small, stimulation operations will be further hindered. As a general rule, in deepwater Gulf of Mexico, 8-1/2” ID pipe across the reservoir is required, with a 9-1/2” ID minimum 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 challenges.[9]

2) Well Intervention Systems

FINDING: Intervention operations on deeper and higher-pressure wells may exceed the capacity of available equipment. Additional development will 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.[10] 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 low cost reserve access 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 from the existing wellbore. 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 worst case discharge loads from a shut-in pressure as well as an APB perspective. The WCD design criterion may inhibit the use of existing wells, creating the potential loss of reserves.

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.[11] 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 been 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, distributed measurements of wellbore pressure and temperature are possible along the drill string to enhance monitoring of hydraulics and hole cleaning. The ability to read downhole temperature and pressure data in real-time, 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 such that the target interval can be reached with the desired casing size. Several managed pressure drilling technologies for use in subsea applications are under development at this time. These technologies optimize the pressure profile imposed on the open hole. Using these technologies, wellbore pressures are managed in a way that allows for longer open hole intervals, preserving hole size. 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 in shallow water, deepwater or onshore test environments.[12]

7) Other Technologies

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

- Wireless annular pressure and temperature monitoring
- Wireless pressure monitoring across mechanical barriers
- 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 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 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 compliance with SEMS.

3) Gaps and Issues – Regulations, Standards, Practices, Collaboration, & Technologies

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 BOEMRE 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 – 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.

d) Regulations – BOP Test Frequency (Workovers and Interventions)

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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.

e) 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, a departure was requested to extend actuation to the next trip up in to the casing, if hole conditions are unstable. 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 getting stuck when function testing the diverter system. Pulling out of the hole increases the risk of a well control situation by swabbing in the well. Alternatively, getting stuck can result in more risk. For example, if the hole becomes packed off, circulation to kill the well is no longer possible. Denying this waiver creates additional risks to operational safety.

f) 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 30 days, in conjunction with the required 30 day pressure tests. 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).

g) Regulations – Surface ROV Function Tests

A clarification of the regulations is needed. 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. A good example is the "All Stabs Retract" function. 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 is no reason to require that this feature be tested. Another 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. There is no need to require the testing of this feature.

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.

h) Regulations – Requirement for Annual Test of Sub-surface Safety Valves

Operators have experienced problems with re-opening sub-surface safety valves during the required annual tests. It is recommended that this required test frequency be reviewed.

i) 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 screening tool does have some guidance regarding different gas gradient assumptions based on well depth but nothing is stated in the CFR or elsewhere in the regulations.

Note - this is a key issue as the currently imposed "worst case" requirements are restrictive and there is a lot of work being done to come up with a better methodology. Before Macondo there were many variations of the calculation in use.

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

Rather than requiring BOEMRE approval, regulations might provide that a negative test be performed prior to displacing and also to require the displacement to 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.

k) 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.

l) 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.

m) 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 to more fully in order to realize the benefits. Clearly, all parties share the benefit from the reduction in accidents.

n) Standards – Riser Fatigue and Failure

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

o) Collaboration– Well Design

With respect to comment BOEMRE #1 regarding salt integrity, industry could benefit from a combined effort to utilize available formation integrity test (FIT) data (and other relevant information) to define a model which supports 'safe FIT' limits relative to overburden pressure.

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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 BOEMRE 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))
- "… employees are 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))
- "… 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?

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- 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
- 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.

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E) Regulatory Comments

During the development of this white paper the following technical and regulatory comments were received from Benjamin Coco, BOEMRE. They are provided here to provide insight to BOEMRE 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] 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. worst case discharge (WCD) and full wellbore evacuation, in order to access the well's survival and avoid a potential broach to the seafloor.

[3] 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.

[4] 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.

[5] It may not be favorable to allow this (*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.

[6] This **(*APB mitigation*)** should be approached from the worst case scenario (WCD) which would be the worst case discharge with full wellbore evacuation.

[7] 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.

[8] Should develop criteria for when to perform post cement job evaluation not just for these areas 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.

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

[10] These wells would be subject (to) the screening process and some may be rejected as candidates.

[11] 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?

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

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Findings

It is recommended that the workshop include a review of the following findings:

A) Current Technologies & Challenges Implementing those Technologies

Well Design – The Technical Challenges

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

1. **Worst Case Discharge Design Load** – The Worst Case Discharge design load, as currently required by the BOEMRE, is excessively conservative. The mandated design case has resulted in well designs that add operational risk, limit design options, and that exceed operational requirements. Alternatives to this design criterion should be considered by the BOEMRE. The collapse load increase is significant and the value of resisting theoretical collapse should be compared with unintended consequences.

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 Worst Case Discharge load case, it is recommended that WCD not be used to dictate APB mitigations.

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.

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Findings – Question 2: What are the 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 in part a function of annular clearance and centralization. These attributes are particularly important in close tolerance 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 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.

Findings – Question 3: What Challenges Exist 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 will 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.

C) Coordination & Communication to Align the Efforts of Industry & Regulatory Agencies

A discussion of all gaps, issues and opportunities identified in Section C (above).

E) Regulatory Comments

All comments provided by the BOEMRE during the preparation of the draft white paper (see Section E above).

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 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

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