ANNEX IV
Drilling Research Projects

CONTENTS

IV.1 SUMMARY OF PROJECTS

This section of the report provides a summary of some significant recent research initiatives and challenges particular to drilling projects, namely:

- High Pressure and High Temperature Applications;
- Riser Configuration;
- Dynamic Well Control;
- Conductor Casing Integrity;
- BOP Components and Secondary Intervention Systems.

IV.1.1 HIGH PRESSURE HIGH TEMPERATURE

In the quest for difficult to find oil, ever deeper and more challenging wells are being drilled. As the industry pushes towards these deeper wells, drillers tap into hotter geological formations. Given that safety is paramount at these drilling depths, it is prudent to investigate these technologies on a regular basis. Four (4) TA&R projects into drilling applications involving high pressure and high pressure have been presented as representative of some significant recent research initiatives and challenges particular to this topic. These projects are TA&R Projects No. 621, 583, 566, and 519. Detailed summaries of these projects are provided in a later section of this Annex.

IV.1.1.1 Project No. 621 – High Pressure High Temperature (HPHT) Elastomer Evaluation

To evaluate the current status of HPHT (High Pressure, High Temperature) well operations, WEST Engineering was contracted to evaluate risks and identify limitations of the BOP (Blow Out Preventer) equipment in this service. The study found that although the BOP industry had risen to the challenge of HPHT drilling conditions, standardization is lacking in certain areas, however, reasonable confidence can be entrusted in the manufacturer High Temperature ratings, assuming the testing procedures are understood. It is recommended that a greater specificity is developed within the standards with regard to High Temperature testing definitions.

IV.1.1.2 Project No. 583 – Characterizing Material Performance for Design of Sour Service HPHT Equipment in Accordance with API RP 6HP Practices

API is drafting a new recommended practice, API RP 6HP, which address design and design-verification methodology for HPHT drilling and completion equipment. The scope of work in this project encompasses a material testing program to enable operators to safely produce oil and gas from HPHT reservoirs. The main objective of this report was to support technology developed by the API RP 6HP standard by characterizing, through testing, material properties (both strength and fatigue) necessary to perform design verification analyses of HPHT equipment, and qualify selected low-alloy steels. This study provides designers with some material property data necessary to perform this verification analysis in accordance with the API RP. Figure IV.1 shows the reduction in yield strength with increasing temperature for some of the materials analyzed in the report.

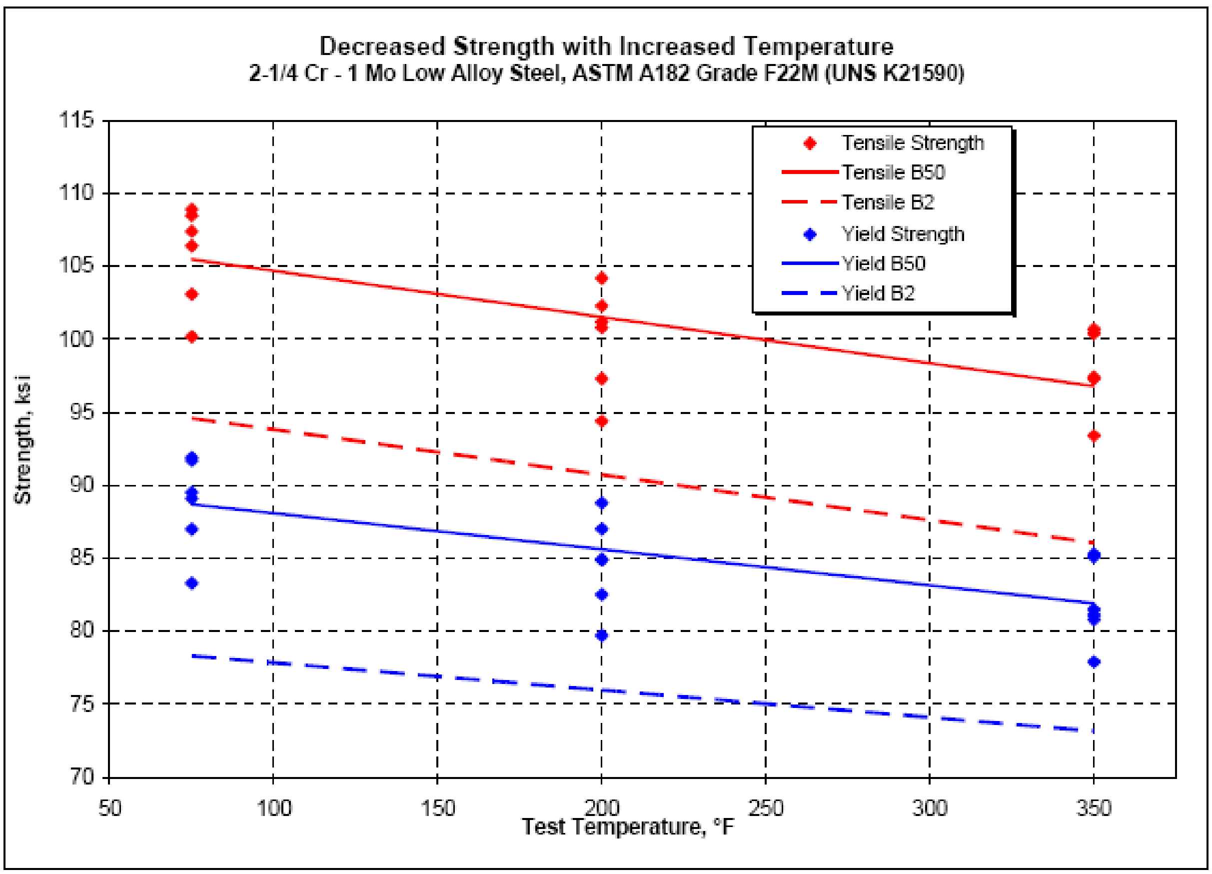

Figure IV.1: Yield Strength Reduction with Temperature

IV.1.1.3 Project No. 566 – Assessment of the Acceptability and Safety of Using Equipment, Particularly BOP and Wellhead Components at Pressures in Excess of the Rated Working Pressure

This research project focuses on the ability of equipment to successfully and reliably operate at or in excess of the manufacturers (and industry's) stated MWP (Maximum Working Pressure). This was achieved by conducting a review of standards and review of discussions were known occasions when equipment was used in excess of pressure ratings. Of the main conclusions it was found that the capabilities of equipment must be defined and available to engineers operating the equipment. It was recommended that the MMS supplement the industry standards in this area to keep regulations current with best available technologies.

IV.1.1.4 Project No. 519 – Technology Gaps in Deep Water HTHP Drilling

The purpose of this study was to identify, understand, and prioritize gaps that exist between current drilling capabilities and required capabilities to drill and complete the High Pressure High Temperature (HPHT) deepwater wells. The major obstacles encountered when drilling extreme HPHT wells are formation and well evaluation tools. Research of elastomers, battery technology, and electronics/sensors are core technologies which require additional focus. If those products appear promising, they must be integrated into workable down hole tools. Projects should be set-up to address advances in cementing and completion, as well as developing investment opportunities to a systems approach of drilling and test facilities to simulate extreme HPHT conditions. Industry groups are currently funding some projects that address many of the issues related to extreme HPHT. Figure IV.2 and Figure IV.3 shows the changes in pressure and temperature with respect to depth.

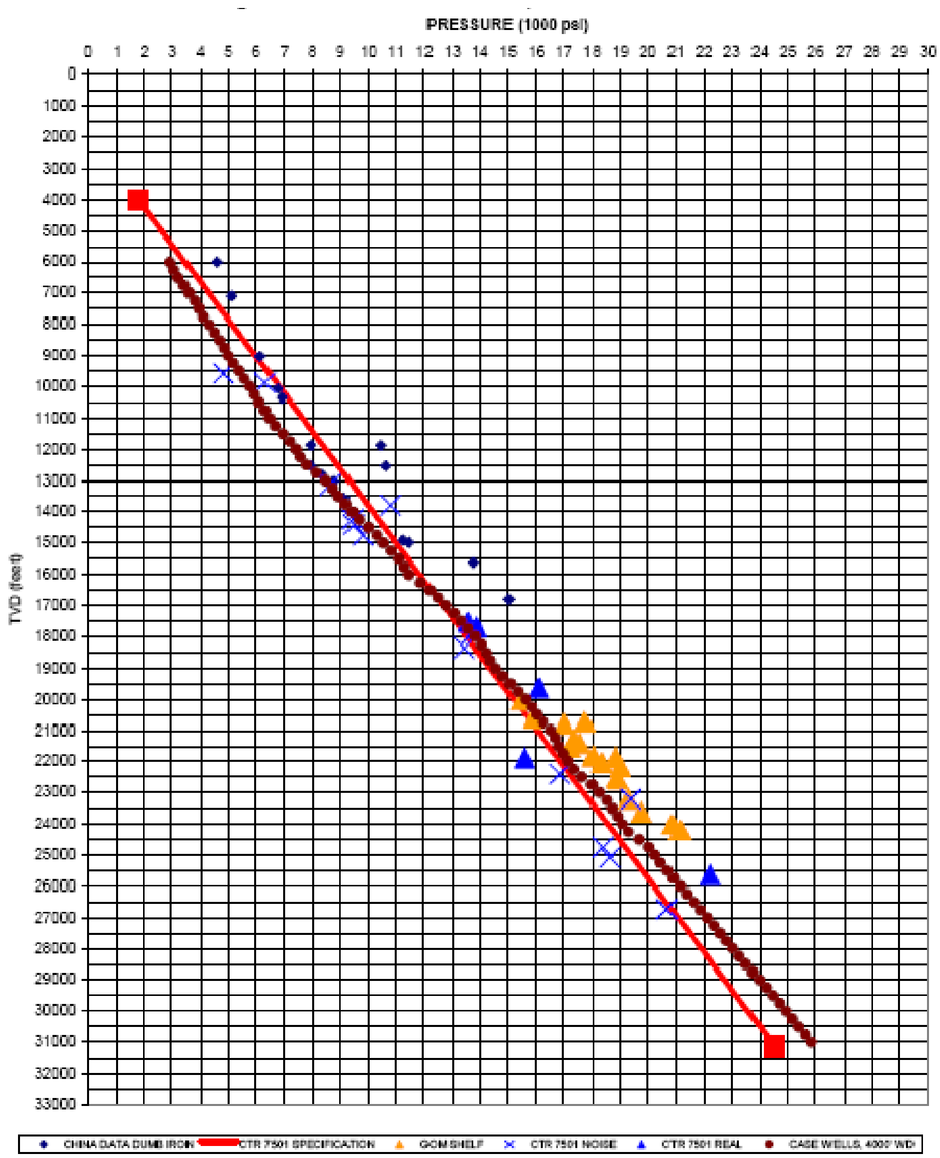

Figure IV.2: Pressure versus Depth for HPHT Wells

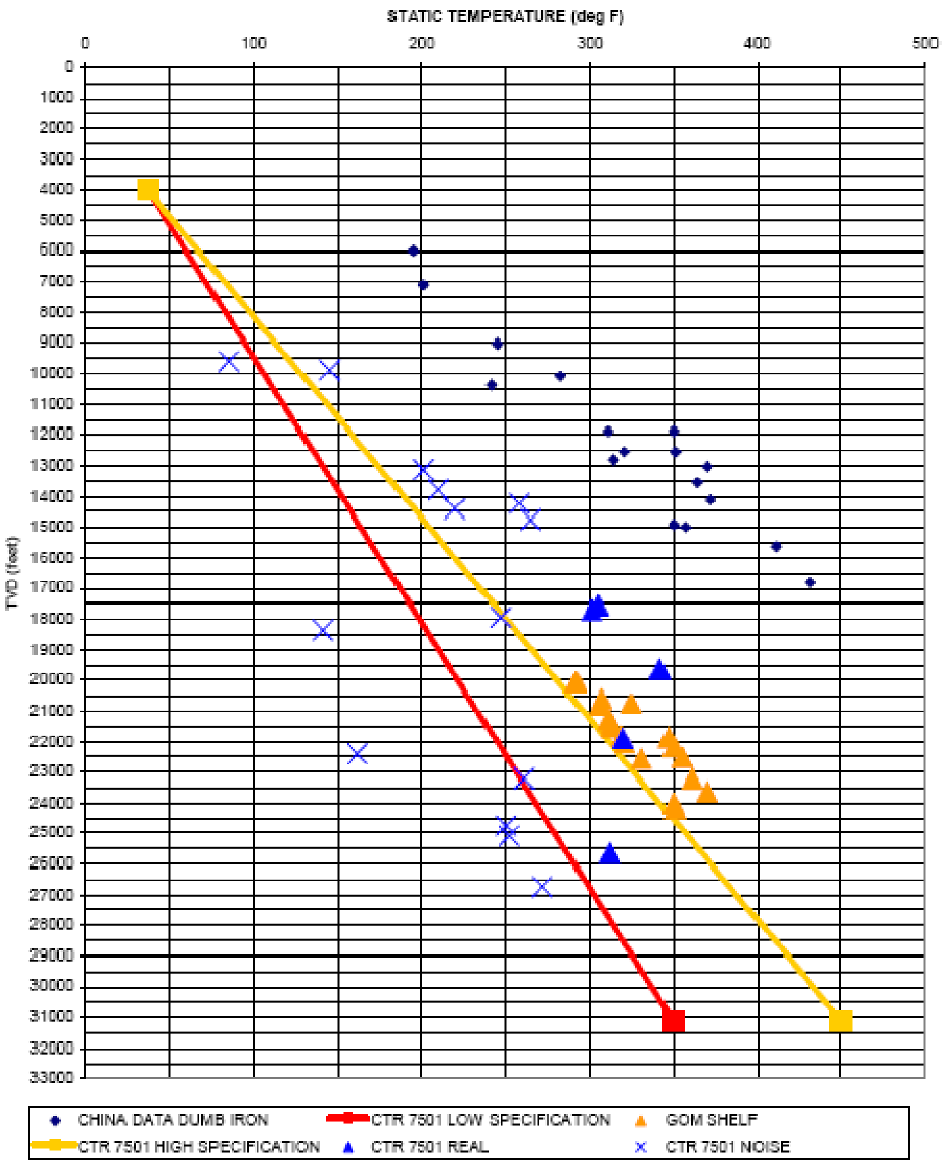

Figure IV.3: Temperature versus Depth for HPHT Wells

IV.1.2 RISK COMPARISON OF RISER CONFIGURATION

The continuous increase in water depths for oil and gas drilling imposes significant challenges on the current available technologies. As such, MMS TA&R Program has funded research into comparing the reliability and integrity of existing and emerging industry advancements, as represented by TA&R Projects No. 606 and 540. Detailed summaries of these projects are provided in a later section of this Annex.

IV.1.2.1 Project No. 606 – Hybrid Well Riser Risk of Failure and Prevention

Deepwater workover, redrill, and sidetrack drilling operations may impose significant costs, time restraints and hazards inherent to riser running / retrieval and simultaneous vessel operations. In an effort to mitigate these challenges, there have been some industry attempts at performing these well interventions through production top-tensioned risers (TTRs). This project thoroughly examined of the causes and probabilities of riser failures from well intervention operations performed through existing single and dual casing production risers with a surface BOP. Highly successful industry participation (data gathered for 21 out of 22 Gulf of Mexico facilities with dry tree production TTRs) showed no loss of riser integrity or any unanticipated adverse results (i.e. "near misses") due to well intervention activities.

Based on worldwide industry experience, exhaustive failure mode lists were compiled with example mitigation, monitoring and inspection techniques specific to drilling operations performed through dry tree production TTRs. Due to the scarcity of quantitative failure statistics and the complex multivariate failure relationships, a risk-based, quasi-qualitative approach was recommended for riser integrity management and selection of mitigation barriers. Prior to well intervention operations, it was recommended that either the production TTR should be designed to handle the additional fatigue and wear associated with drilling, or an engineering assessment should be completed to demonstrate the riser's suitability.

IV.1.2.2 Project No. 540 – Risk Assessment of Surface vs. Subsurface BOP's on Mobile Offshore Drilling Units

In an attempt to mitigate many of the problems associated with deepwater drilling, some operators have either considered using or have used Surface Blow Out Preventers (SBOP's) with small diameter, high pressure risers in floating drilling operations. However, this is relatively new technology, and there is inherent risk in applying any new practices. This report evaluated the risks associated with this new technology in comparison to subsurface BOPs. It was found that the reliability of surface BOPs was almost equal to the reliability of subsea BOP systems, and that the components of the riser system should be analyzed for field specific locations to mitigate against failures. Applications of the technology range from the benign environments of Southeast Asia to more demanding environments in

Brazil and the Mediterranean with water depths also approaching 10,000 feet. Figure VI.3 shows an illustration of the different BOP systems assessed.

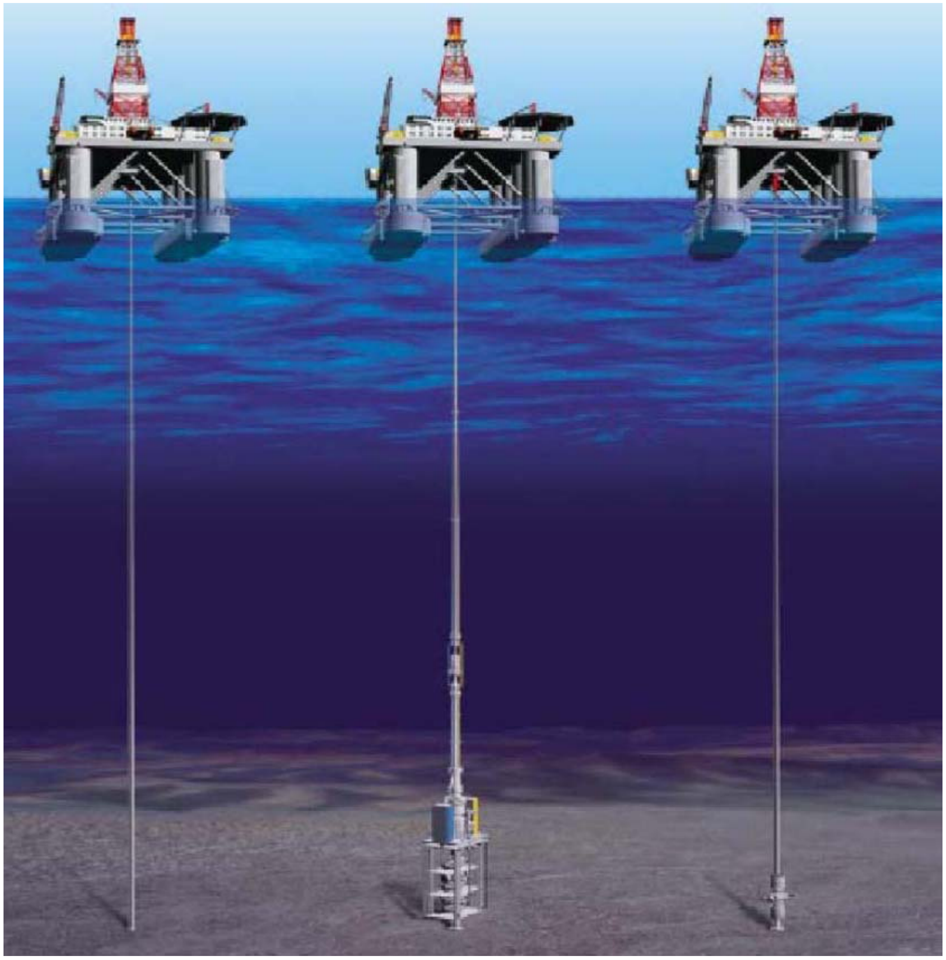

Figure IV.4: Illustration Deepwater Drilling with Surface Blow Out Preventer (SBOP), Subsea Blow Out Preventer (BOP), and SBOP with Shut-In Device (SID)

IV.1.3 DYNAMIC WELL CONTROL

Although a kick incident rarely leads to a full blowout situation, preventing the incident from occurring in the first place is by far preferable. Techniques for dynamic well control (such as underbalanced drilling, managed pressure drilling, and dual gradient) may significantly reduce the risk of formation damage and occurrence of kicks. Four (4) TA&R projects have been have been selected as representative of some of the research into dynamic well control. These projects are TA&R Projects No 582, 541, 474, and 440. Detailed summaries of these projects are provided in a later section of this Annex.

IV.1.3.1 Project No. 582 – A Probabilistic Approach to Risk Assessment of Managed Pressure Drilling in Offshore Drilling Applications

Between 25% and 33% of all remaining undeveloped reservoirs were unfavorable for use of conventional overbalanced drilling methods due in a large part to the increased likelihood of well control problems. Managed Pressure Drilling (MPD) is a tool that is intended to resolve and mitigate chronic drilling problems which contribute to non-productive time. This study examined MPD techniques used to dynamically control annular pressures and thus facilitate drilling of well that might have otherwise been economically unobtainable. From this recommended practices for the use of MPD are presented in the form of the project report.

IV.1.3.2 Project No. 541 – Application of Dual Gradient Technology to Top Hole Drilling

Dual gradient technology may offer potential benefits in this field; if used in the top portion of the well, it would allow conductor and surface casing to be set deeper, and thus allow safer drilling of the intermediate hole. Some of the hazards related to drilling the top hole portion such as methane hydrates, shallow gas, and shallow water flows can be minimized by using dual gradient technology. Dual gradient technology shows great promise for deep water drilling, potentially improving safety, quality, cost efficiency, and environmental impact. Convincing the industry end users (operators and service companies alike) of its merits through education and training is believed to be beneficial. The offshore energy industry hopes to have the industry's first fully integrated and commercialized dual-gradient drilling system operating in deepwater in the Gulf of Mexico by late 2011. Figure IV.5 shows an illustration of a riserless dual gradient system.

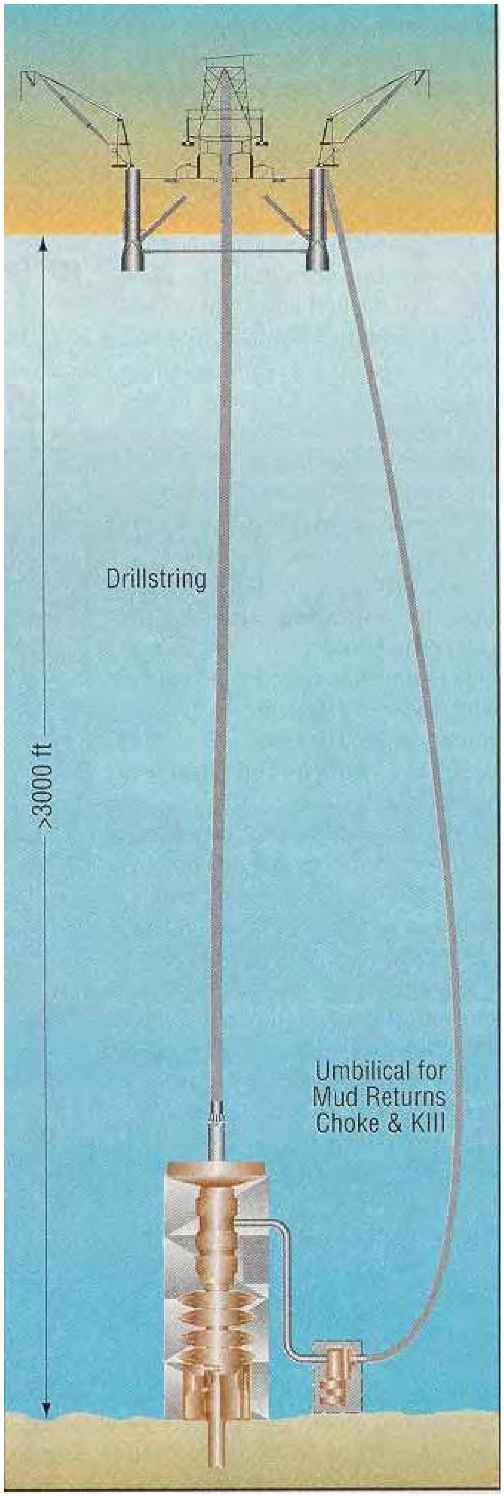

Figure IV.5: Illustration of a Riserless Dual Gradient System

IV.1.3.3 Project No. 474 – Evaluation of Safety Concerns during Well Testing from OCS Drilling Rigs

It is anticipated that flow testing activity of wells is likely to increase to provide more certainty than currently obtained by static testing alone. This report examined the impact on well test safety when moving into deeper waters, the increased possibility of encountering high pressure or high temperature conditions in deep gas wells, and also the possibility of increased arctic activity. The report outlines Recommended Practices based on an extensive review of current industry practices and on input from representatives from the main parties concerned with well testing operations, Offshore Operators, Drilling Contractors, and Well Test Service Companies. Figure IV.6 shows an example of watch circles which are critical during well testing.

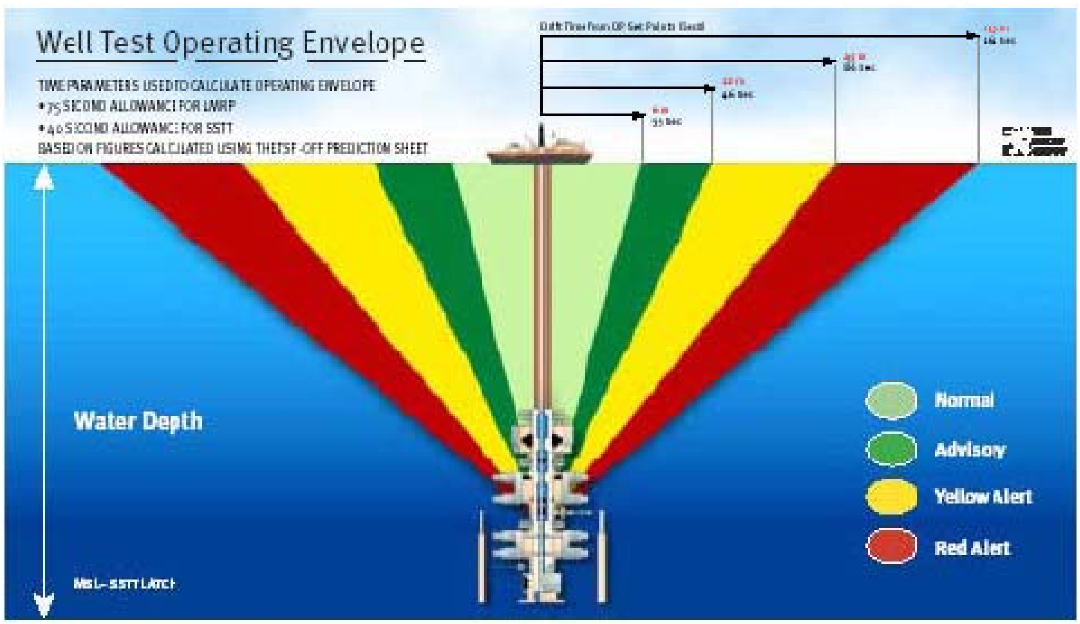

Figure IV.6: Example of Watch Circles for Well Testing Operations

IV.1.3.4 Project No. 440 – Development and Assessment of Well Control Procedures for Extended Reach and Multilateral Wells Utilizing Computer Simulation

To gain a better understanding which factors have a significant effect on choke pressures and gas-return rates for various kick scenarios, this report performed an extensive simulation study of vertical, directional, horizontal, and Extended Reach Drilling (ERD) wells. From this conclusions are drawn relating to kick size, choke pressure, and true vertical depth. Simulation analysis outlined the measures which can be taken to mitigate kick sizes. Figure IV.7 shows the maximum choke pressure and gas return rate that are obtained for increasing kicks in increasing water depths.

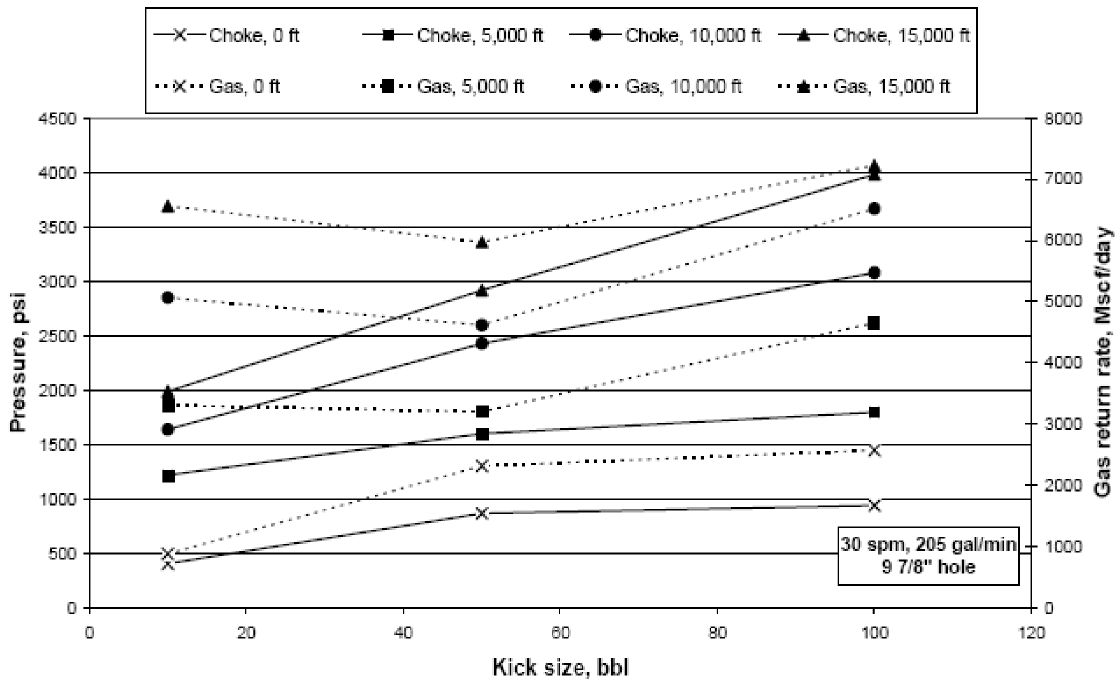

Figure IV.7: Maximum Choke Pressure and Gas Return Rate for Various Kick Sizes and Water Depths

IV.1.4 CONDUCTOR CASING INTEGRITY

Conductor casing functions to: control well pressure, prevent wellbore cave-ins, isolate various subsurface zones, and most importantly confine production fluids to the wellbore. Maintaining conductor casing integrity has long been identified as a crucial concern, as represented by TA&R Projects No. 495 and 426. Detailed summaries of these projects are provided in a later section of this Annex.

IV.1.4.1 Project No. 495 – Risk Assessment and Evaluation of the Conductor Pipe Setting Depth on Shallow Water Depths

The aim of this project was to conduct a Risk Assessment and evaluation of the conductor pipe setting depth on shallow water wells and to write guidelines as to how to select conductor setting depths. This was achieved by conducting a literature review and analysis of the strength of shallow water sediments, along with an evaluation of the effect of gas migration into shallow water sediments on conductor casing setting depths. The report highlighted that casing depth for conductor casing cannot be based on tradition, and that conductor and casing depths must be determined for each individual well/platform.

IV.1.4.2 Project No. 426 – Long Term Integrity of Deep-Water Cement Systems

The overall objective of this project was to evaluate the ability of cement compositions to provide well integrity and zonal isolation through zones in which subsidence, compaction, and excessive stresses can be long-term problems. The project primarily focused on deepwater applications, but general applications were also examined. Based on a literature review and on Participants opinions as to the factors that affect the integrity of the annular seal, a list of mechanical properties and mechanical integrity failure modes to test was made out. Analysis was conducted for soft, intermediate and hard formations with the four main cement systems. Cyclic loading conditions (Pressure & Temperature) were applied for integrity testing. The configuration used for the testing analysis is shown in Figure IV.8.

It is recommended that in order to extend the analysis to a broader range of real-well conditions, more precise measurements and additional data points are required for confirmation of trends; this implies further work to understand the energy absorption of the various wellbore components, and testing of additional cement and formation types.

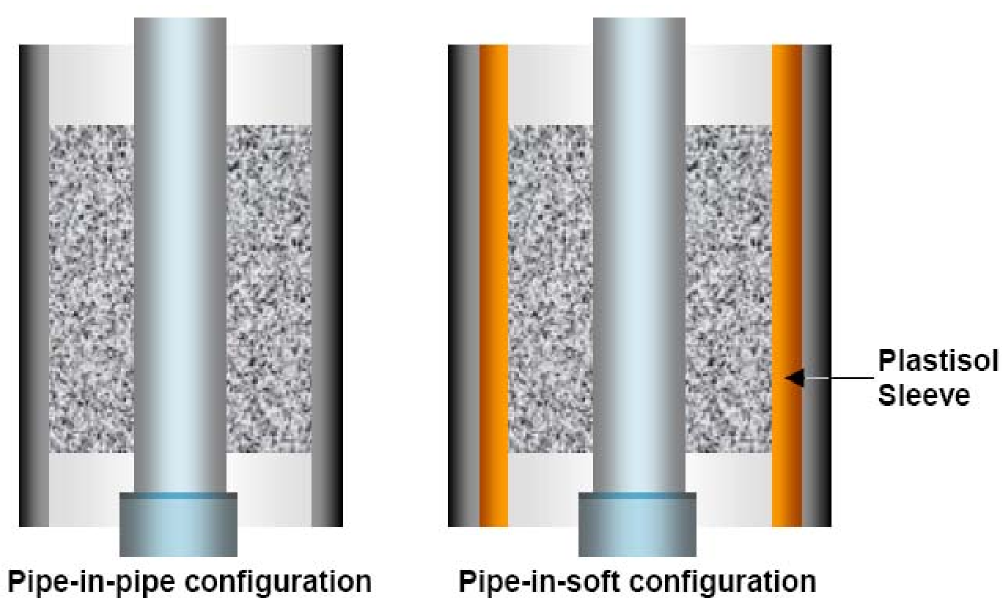

Figure IV.8: The Two Configurations Used for the Casing Testing

IV.1.4.3 BOP Components and Secondary Intervention Systems

The last safety barrier in drilling operations is the Blow Out Preventer (BOP). Maintaining BOP reliability is crucial to safe drilling operations. MMS TA&R Program has funded significant research into assessing the reliability and integrity of BOP systems, particularly of the shear rams. Recent studies may be represented by TA&R Projects No. 463, 455, and 431. Detailed summaries of these projects are provided in a later section of this Annex.

IV.1.4.4 Project No. 463 – Evaluation of Shear Ram Capabilities

This study reviews existing shear data provided by BOP manufacturers in an attempt to better understand the factors governing shear ram capabilities, considering drill pipe mechanical properties (yield strength, ultimate strength, and ductility) and examining the shear force equation derived from the Distortion Energy Theory. The study developed equations that provide a better model of the available shear data than those used by the BOP manufacturers, using indicators both related to Distortion Energy Theory (i.e. based on yield strength) and to ductility of pipe material. An empirical shear force formula was also proposed for cases where only yield strength of the material is available for the drill pipe in use. Figure IV.9 shows the typical shearing forces during the shearing operation.

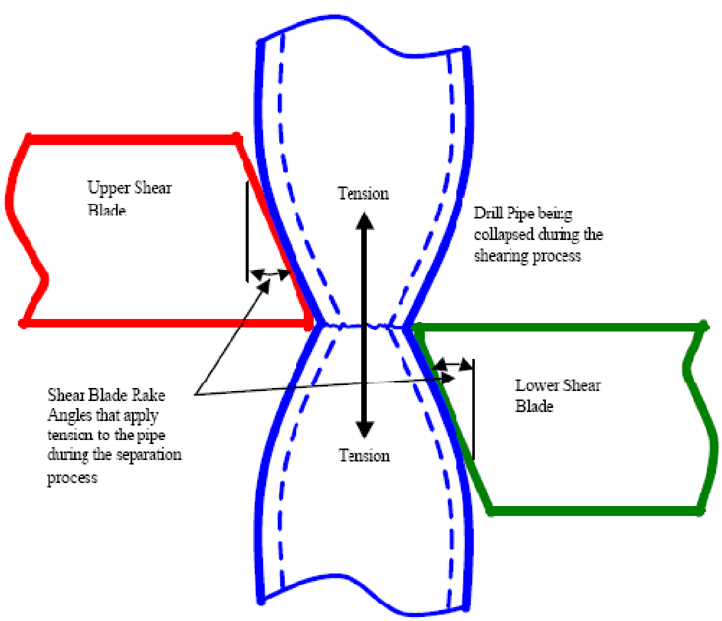

Figure IV.9: Schematic Representation of Upper and Lower Shear Blades Crushing the Drill Pipe and Beginning the Shearing Operation

IV.1.4.5 Project No. 455 – Review of Shear Ram Capabilities

This study examined shear rams capabilities data from drilling rigs that WEST Engineering Services, Inc. had experience in dealing with during a recent round of upgrades. The purpose of the project was to obtain a snapshot of actual shearing capabilities of rigs that are working on the OCS (i.e. subsea BOP's). In addition, a review of API Specification 16A requirements and procedure is also presented. It was concluded that greater specificity in the guidelines would ensure more uniform testing and results that are closer to actual shear values; furthermore, additional factors related to operating conditions should be considered for more realistic assessment of capabilities. It was recommended that additional rigs should have their shear rams capabilities tested, so as to extend the available database and to confirm methods of estimating shear pressure.

IV.1.4.6 Project No. 431 – Evaluation of Secondary Intervention Methods in Well Control

The aim of the study was to provide a review of the design and capabilities of various secondary BOP intervention systems as recently installed on new build and significantly upgraded drilling rigs circa 2004. In addition, it identifies the best systems and practices currently in use as well as opportunities that could enhance the effectiveness of these systems. It is recommended that a shear circuit should be added to riser systems to provide an automatic closure of the well in the event that another cause accidentally unlatches the LMRP.

IV.2 HIGH PRESSURE HIGH TEMPERATURE

IV.2.1 PROJECT NO. 621 – HIGH PRESSURE HIGH TEMPERATURE (HPHT) ELASTOMER EVALUATION

IV.2.1.1 Introduction

This report was produced for the MMS by West Engineering Services Inc., and was issued in June 2009.

IV.2.1.1.1 Background

In the quest for difficult-to-find oil, ever deeper and more challenging wells are being drilled. As the industry pushes towards deeper wells, drillers tap into hotter geological formations. Since safety is paramount at these drilling depths, it behooves the industry to investigate the state of High Pressure High Temperature (HPHT) technology every few years, looking for advances/breakthroughs in technology or required revisions to existing standards. The present study builds upon previous studies from the mid 1990s and assesses the changes since then.

IV.2.1.1.2 Technical Scope

In order to evaluate the current status of HPHT (High Pressure, High Temperature) well operations, WEST was contracted to evaluate risks and identify limitations of the BOP (Blow Out Preventer) equipment in this service.

IV.2.1.1.3 Study Limitations

The study primarily made use of three sources of information: WEST in house documents and staff experts with 20+ years of experience; a survey of Original Equipment Manufacturers (OEMs) in which a questionnaire was mailed out to three companies that make BOPs and their answers analyzed; publically available materials such as online marketing literature, articles in trade journals, and technical papers. Given the sources of information it can be argued that the study is subjective in nature.

IV.2.1.2 Project Conclusions

IV.2.1.2.1 Key Conclusions and Results

The main conclusions of the report are:

- The BOP industry lacks a true high temperature testing standard. API 16A [7] specified one hour hold time is not adequate to reflect real world BOP conditions. However, an acceptable degree of confidence can be entrusted in manufacturer High Temperature ratings due to manufacturer testing, although variation in testing is found to occur between manufacturers;
- Pressure testing requirements are well understood, while temperature testing requirements are somewhat vague. Section 5.7 of API 16A [7] clearly defines pressure testing for BOP operational characteristics, and are outlined with a high level of specificity. However, the same level is clarity of not apparent in section 5.8 when discussing temperature testing;
- One must consult the manufacturer data for continuous high temperature rating, to determine the maximum temperature at which the packer material of the BOP can hold the pressure indefinitely. Details such as the test fluid and locks-only sealing capability are not generally available, nor are they specified in the HT portion of API 16A;
- High temperature and pressure are unlikely to occur in the actual operating milieu of a BOP, thus the API 16A temperature test could be regarded as subjecting the elastomers to an extreme condition;
- It is WEST's understanding that during operation it would be expected that as the pressure builds across closed rams, temperature falls. In the subsea environment the cold ocean acts as an enormous heat sink, cooling the BOP rapidly. As the wellbore pressure increases to reservoir pressure minus hydrostatic head, temperatures will cool to ambient;
- Thermal modeling with FEA methods is an excellent tool by which to fine tune BOP seal requirements.

IV.2.1.2.2 OSER Goals

This project addressed the safety concerns and testing requirements relating to the performance of BOP in HTHP service. This is inline with goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.2.1.2.3 Recommendations

The following recommendations are made:

- Greater specificity is required in the High Temperature testing definitions, which should be representative of more realistic operating conditions;
- A thermal soak and/or longer high temperature hold time is recommended to better represent typical wellbore situations associated with BOP closing and sealing;
- Multiple test points covering a range of temperatures and pressures would form a more complete basis for decisions regarding a BOP's ability to meet the demands of various well conditions.

IV.2.1.3 Current State of Knowledge

The BOP industry has risen to the challenge of HPHT drilling conditions using augmented API testing methods. Standardization is lacking in certain areas, however reasonable confidence can be entrusted in manufacturer HT ratings, assuming the test procedure is understood. A higher level of specificity in these procedures would make it easier to compare temperature ratings across the spectrum of manufacturers.

IV.2.2 PROJECT NO. 583 – CHARACTERIZING MATERIAL PERFORMANCE FOR DESIGN OF SOUR SERVICE HPHT EQUIPMENT IN ACCORDANCE WITH API RP 6HP PRACTICES

IV.2.2.1 Introduction

This report was produced for the MMS by Stress Engineering Services Inc, and was issued in March 2008.

IV.2.2.1.1 Background

The Gulf of Mexico (GOM) is reported to contain substantial undeveloped oil and gas reserves in high pressure high temperature (HPHT) reservoirs. These more challenging environments represent the future of petroleum production in the GOM and that they will form a significant proportion of future additions to USA domestic reserves, if these HPHT fields can be produced safely and economically. Safe development of these reserves requires equipment such as wellheads, trees, and blowout preventers that are manufactured and certified for use in HPHT environments. To aid the industry in these developments, API is drafting a new recommended practice, API RP 6HP [8], which address design and design-verification methodology for HPHT drilling and completion equipment. The scope of work was to encompass a material testing program to enable operators to safely produce oil and gas from HPHT reservoirs. Completion of the program will ultimately support more widespread development of HPHT reserves by providing designers with some of the essential material properties needed to perform design.

IV.2.2.1.2 Technical Scope

The objective of this materials characterization program was to obtain material properties for performing design verification analyses of HPHT equipment in accordance with API RP 6HP, and specifically focused on 2¼ Cr – 1 Mo quenched and tempered low alloy steel. A summary of the objectives were to:

- Support technology developed by the API RP 6HP standard by characterizing, through testing, material properties (both strength and fatigue) necessary to perform design verification analyses of HPHT equipment;
- Qualify selected low-alloy steels to determine their suitability for use in manufacturing HPHT drilling and completion equipment;
- Document results of the materials characterization;
- Recommend specific improvements for existing and new technologies that are suitable for testing and evaluating materials for HPHT applications.

IV.2.2.1.3 Study Limitations

In preparing this report, Stress Engineering Services (Stress) has relied on information provided by MMS. Stress has made no independent investigation as to the accuracy or completeness of such information and has assumed that such information was accurate and complete.

IV.2.2.2 Project Conclusions

IV.2.2.2.1 Key Conclusions and Results

The main conclusions of the project were:

- Forged blocks used for material testing should probably be post-weld heat treated (PWHT) prior to specimen preparation and testing. This may result in a closer representation of the material strength properties due to PWHT during the manufacturing process;
- The Association of Wellhead Equipment Manufacturers (AWHEM) recommendation for strength reduction factor of 0.91 for 350°F for 2¼ Cr – 1 Mo material should be applied;
- Values for the modulus of elasticity as a function of temperature as defined in ASME Section II Part D [9] should be used for design purposes;
- The equivalent plane strain fracture toughness tests in air resulted in a mean stress intensity factor, B_{50}, of 225 ksi·√inch and a lower bound, B_1, value of 203 ksi·√inch;
- The equivalent plane strain fracture toughness tests in seawater with cathodic protection resulted in a mean stress intensity factor, B_{50}, of 199 ksi·√inch and a lower bound, B1, value of 156 ksi·√inch.

IV.2.2.2.2 OSER Goals

This project determined the suitability of low-alloy steels, for use in manufacturing HPHT drilling and completion equipments, through materials characterization to obtain material properties for performing design verification analyses. This is inline with goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.2.2.2.3 Recommendations

The report makes the following recommendations:

- Within the present study, a good correlation of material modulus was observed with data published in ASME [9] Section II Part D for 2¼ Cr – 1 Mo material, which provides a smooth curve fit over the temperature range of -325°F to 1400°F. Therefore, it is recommended that the ASME data [9] be used for modulus;

- Based on low values and variability of the fracture toughness data, performance data from the H_2S environmental fracture toughness testing should not be used for design purposes, and is provided in this report for information only;
- From the fatigue analysis it was shown that more research is needed to better understand the variables which affect the crack growth rate performance.

IV.2.2.3 Current State of Knowledge

This project supports more widespread development of HPHT and sour HPHT reserves by providing designers with some of the material property data necessary to perform design verification analyses in accordance with American Petroleum Institute Recommended Practice 6HP (API RP 6HP) [8].

IV.2.3 PROJECT NO. 566 – ASSESSMENT OF THE ACCEPTABILITY AND SAFETY OF USING EQUIPMENT, PARTICULARLY BOP AND WELLHEAD COMPONENTS, AT PRESSURES IN EXCESS OF THE RATED WORKING PRESSURE

IV.2.3.1 Introduction

This report was produced for the MMS by West Engineering Services Inc., and was issued in October 2006.

IV.2.3.1.1 Background

As a result of the offshore oil and gas industry's ongoing expansion of technology frontiers, fields with ever more challenging conditions are being explored, tested, producing challenging conditions. This research project focuses on the high pressure facet of the technology frontier, specifically the ability of equipment to successfully and reliably operate at or in excess of the manufacturers (and industry's) stated MWP (Maximum Working Pressure).

IV.2.3.1.2 Technical Scope

The objectives of the research in this report were to:

- Review standards currently available for the manufacture of BOP and wellhead equipment relative to rated working pressure and evaluate their adequacy;

- Review current regulations concerning pressure containment issues listed above;
- Identify areas for clarification and improvement to existing standards compared to current regulations;
- Review and discuss known occasions where equipment was used in excess of pressure ratings;
- Review regulatory and current practices for defining MASP (Maximum Allowable Surface Pressure), including differences due to water depth (i.e., influence of OD);
- Propose a performance based system that qualifies equipment for working above its Maximum Allowable Working Pressure (MAWP), including limitations and applications.

IV.2.3.1.3 Study Limitations

The project report is presented in a manner which is not concise and lacking in structure, as such it is difficult to ascertain the key conclusive points and recommendations of the research.

IV.2.3.2 Project Conclusions

IV.2.3.2.1 Key Conclusions and Results

The main conclusions of the project were:

- Rams and control systems are critical when working Blow Out Preventer (BOP) equipment at or near its MWP; testing procedures must be developed and practiced to verify these systems are operational, without causing downtime from testing wear;
- The high downtime attributed to control systems is caused by the competence of the technician and the quality systems in place that support the technician;
- It is believed that the testing above MWP of the closing mechanism of the BOP, as specified in API 16A [7], is not routinely conducted;
- There are a number of areas where the industry does not conform to API 16A, including: Design Verification Testing, Operating Manual Requirements, and Requirements for Repair and Remanufacture;
- Best Available and Safest Technology (BAST) will not be achieved if API Q1 [12], “Specification for Quality Systems”, is not utilized;
- There is a need for the MMS to supplement industry standards and to keep regulations current with best available technology;

- Over pressure created by the hydrostatic pressure of the mud should be considered when defining test pressure;
- If well control equipment fails pressure test at its MWP and the repair cannot be accomplished quickly, the equipment may be down rated or removed from service;
- The capabilities of the equipment must be defined and available to engineers operating this equipment. Three operating modes negatively impact the ability of ram type BOPs to seal MWP: Hang-off, Stripping, and Shearing;
- For coiled tubing equipment it has always been considered an industry "best practice" to avoid working at pressures above maximum rated working pressure of well control equipment, and use at pressures above MWP should only be allowed under the most extreme conditions;
- The higher operating pressure required for the Variable Bore Rams (VBRs) should be considered in accumulator volume calculations, and the operating pressure required to achieve a low and high pressure seal on the VBRs should be recorded.

IV.2.3.2.2 OSER Goals

The project assessed the acceptability and safety of using equipments, particularly BOP and wellhead components, at pressures in excess of the rated working pressure. This is inline with goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.2.3.2.3 Recommendations

The report makes the following recommendations:

- BOP stack or failsafe valves should be designed to API Spec 17D [11], rather than Spec. 6A for High Pressure High Temperature (HPHT) applications;
- Wellhead and Riser Connectors should be wellbore tested between wells on the stump without operating pressure on the close side, and periodically tested for back-driving;
- Wellbore tests using the ram locking system only (without close operating pressure) should be conducted at some frequency;
- Operational characteristics test results for well control equipment should be available on the rig, and establish an API Q1 quality system [12] for well control equipment. The MMS should consider recognizing API RPs as minimum standards, and supplementing as appropriate;

- MMS prescriptive standards should be consistent or to a higher standard than API. Confusion arises when the MMS standards are lower than industry standards;
- Upgrade API Specification 16A [7] annex D on design temperature verification testing, for temperature effects on BOP elastomers;
- The MMS should supplement the minimum standards API publishes on Poor Boy Degassers.

IV.2.3.3 Current State of Knowledge

Further development in high pressure well equipment is described in a recent report by West Engineering report in TA&R Project 621.

IV.2.4 PROJECT NO. 519 – TECHNOLOGY GAPS IN DEEP WATER HTHP DRILLING

IV.2.4.1 Introduction

This report was produced for the MMS by Triton Engineering Services Company, and was issued in June 2006.

IV.2.4.1.1 Background

The purpose of this study was to identify, understand, and prioritize gaps that exist between current drilling capabilities and required capabilities to drill and complete the High Pressure High Temperature (HPHT) deepwater wells. HPHT conditions are defined as wells drilled 27,000 ft below the mud line with reservoir temperatures in excess of 350°F and pressures of 24,500 psi. The aim is to gain an understanding of these gaps that is sufficient for vendors to develop project scope, time, and cost proposals to close identified gaps.

IV.2.4.1.2 Technical Scope

Two parallel approaches were pursued to document the industry's capabilities in HPHT operations. These were:

- Analysis of Historic Well Data;
- Survey of Industry Service Providers.

These approaches were designed to contrast what the industry believes (claims) are its performance limits versus what has actually been achieved in recent applications.

Both historic well data and service company information were then used to define limits of existing skills, equipment, and services. From there, gaps were identified and estimated the time, cost, and technical complexity required to close those technology gaps.

IV.2.4.1.3 Study Limitations

This study included thirty-one deepwater wells and four "deep" shelf wells. Most of these are in the Gulf of Mexico (GOM). Data for the deepwater wells were derived from Triton's in-house database or contributed by several participant companies.

The service industry was surveyed to document the capabilities of current tools and systems. The project team developed a series of interview questions, and interviewed several service companies in an iterative process. Physical design drivers were defined, and the current practices were identified based on their response.

It is worth noting that both these approaches are subjective in nature.

IV.2.4.2 Project Conclusions

IV.2.4.2.1 Key Conclusions and Results

The main conclusions of the project were:

- The major obstacles encountered when drilling extreme HPHT wells are formation and well evaluation tools. Research of elastomers, battery technology, and electronics/sensors are core technologies which require additional focus. If those products appear promising, they must be integrated into workable down hole tools;
- Well drilling will also benefit from projects that optimize Rate of Penetration (ROP) through careful selection of bits, drilling fluids, motors, and string design. Test fixtures will be required to establish equipment design criteria and to provide a means for testing well equipment;
- HPHT wells will soon reach limits of 30,000 psi and/or temperatures up to 500°F. The effect of high temperatures on equipment continues to be a primary obstacle in successful HPHT well completion. In addition, the continuing demand for real-time

data gathering and formation evaluation remains unmet even though the risk associated with down hole extreme conditions would be minimized;

- There is an irrefutable need for continuous research and development in oilfield cementing. Without these solutions, the industry cannot continue to effectively and efficiently pursue oil and gas in the most challenging environments;
- Precise funding mechanisms for each aspect of technology research and development need to be defined. Participants in any or all projects will come from the group of operators, possibly drilling contractors, service companies, and regulatory agencies. Currently, operators fund specific equipment and services necessitated by field demand rather than financially supporting product development prior to the actual need;
- It makes sense for oil companies to share lessons learned between other operators and drilling contractors to progress technologies quicker;
- Flow assurance is the most critical issue in completion technology since production is paramount to the success of these developments, with advances needed in requirements of completion fluids, completion equipment, and perforating.

IV.2.4.2.2 OSER Goals

The project documented the industry's capabilities in HPHT operations and identified the gaps that exist between current capabilities and required capabilities to drill and complete the defined HPHT deepwater wells. The aim is an understanding that is sufficient for vendors to develop project scope, time, and cost proposals to close identified gaps. This is inline with goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.2.4.2.3 Recommendations

The report makes the following recommendations:

- Projects should be set-up to address advances in cementing and completion, as well as developing investment opportunities to a systems approach of drilling and test facilities to simulate extreme HPHT conditions;
- Hire/appoint an engineer or committee to champion this effort;
- Expand the group of operating companies and proxies in the service sector to include shelf drillers;
- Construct a detailed data base of all related past and current HPHT failures;

- Monitor progress of all service companies in regard to improved tool performance;
- Work with operations personnel to optimize procedures for use of smart tools;
- Integrate research efforts and focus on cooperation and technology application;
- Drill wells with the intention of sharing HPHT equipment data.

IV.2.4.3 Current State of Knowledge

Industry groups are currently funding projects that address many of the issues related to extreme HPHT. More than half of these projects are devoted to technology that will enable Logging While Drilling (LWD)/Measurement While Drilling (MWD) and logging in these environments.

IV.3 RISER CONFIGURATION

IV.3.1 PROJECT NO. 606 – HYBRID WELL RISER RISK OF FAILURE AND PREVENTION

IV.3.1.1 Introduction

IV.3.1.1.1 Background

To mitigate the cost and time restraints associated with deepwater workover, redrill, and sidetrack drilling operations, some operators have either considered or performed these operations through existing single or dual bore production top tensioned risers.

In response, MMS requested an investigation into the causes and probabilities of top-tensioned riser (TTR) failures from workover and drilling operations through existing single and dual casing production risers with a surface Blow-Out Preventer (BOP). Specific attention was paid to potential wear issues due to rotating drill pipe within riser systems that have already been in service for a substantial period of time, and that may have been subject to corrosion and VIV fatigue.

IV.3.1.1.2 Technical Scope

The tasks for this project were to:

- Survey industry to assess the equipment, deployment and operating conditions, and frequency of use of surface BOPs for workover operations from floating production facilities through existing single and dual bore production TTR systems;
- Compile exhaustive failure mode lists with example integrity management measures specific to drilling operations performed through dry tree production TTRs, based on worldwide industry experience;
- Establish current state-of-the-art and developing mitigation, inspection and monitoring techniques for these operations.
- Provide a methodology for assessing the risk posed to existing single and dual cased production TTR systems used for workover operations.

Analysis of frequency of occurrence of loss of integrity with a critical review of cause and effect was also to be included. However, the industry surveys completed indicated that operators in the Gulf of Mexico had not experienced a loss of production TTR integrity due to these workover operations. Operators also reported no unanticipated instances of wear or damage from drilling, which are the other major riser integrity concerns identified for the operations. As such, analysis of frequency of occurrence of loss of integrity was not conducted.

Information was compiled from industry surveys to operators and vendors, one-on-one interviews, public domain information and company internal project experience.

IV.3.1.1.3 Study Limitations

- It was a fundamental assumption that all riser systems have been designed in accordance with a recognized industry code of practice for riser design.
- Failure modes considered by this approach are associated with structural failure of a riser system (e.g. rupture or leakage) rather than functional failures (e.g. blockage). Additionally, any failure of a riser component (e.g. buoyancy module) was treated as an intermediary step leading to the structural failure of the system.
- Focus was on long-term failure mechanisms such as wear; instead of more immediate failure scenarios such well control events. Limited discussion of well control issues. Potential blowout was not explicitly discussed, although over-pressurization was considered. Also, there is no discussion of failure modes potentially mitigated by performing these operations through a production TTR.
- Due to the lack of historical data regarding GOM production TTR drilling applications, some of the possible failure modes reflect the best guesses from operators' experience in other regions around the world.

IV.3.1.2 Project Conclusions

IV.3.1.2.1 Key Conclusions and Results

The industry survey was highly successful; responses were received for 21 out of 22 Gulf of Mexico facilities with dry tree production top-tensioned risers (TTRs). In summary, the results are:

- Potential failure modes for production TTRs during workover operations have been compiled as a part of this study. As expected, riser wear and additional fatigue have been identified as the most critical hazards. Drilling-induced vibration was raised as a potential challenge for smaller diameter risers and as a potential root cause for unaccounted fatigue cycles.
- When drilling operations have been performed through production TTRs, the TTRs have either been designed to handle the additional fatigue and wear associated with drilling, or the operators have employed additional barriers (e.g. wear sleeves or non-rotating protectors) to mitigate these risks.
- Current state-of-the-art and developing inspection, monitoring and other risk-mitigating techniques for production TTRs were thoroughly interrogated, emphasizing techniques specifically for workover operations. Failure modes were associated with applicable measures.

IV.3.1.2.2 OSER Goals

At the time of this report, TTRs represented approximately 65% of the production risers in North America, with some approaching 20 years in service. Retaining the structural integrity of these aging assets is of paramount import to the goals of the OSER. This project thoroughly investigated typical and best industry practices, and provided recommendations on how to incorporate this knowledge into a risk-based integrity management approach.

IV.3.1.2.3 Recommendations

The authors recommended:

- If the production TTR was not designed to handle the additional fatigue and wear associated with drilling, then an engineering assessment should be completed to demonstrate the riser's suitability.
- A risk-based, quasi-qualitative approach for riser integrity management and selection of mitigation barriers should be implemented, due to the scarcity of quantitative failure statistics and multivariate failure relationships.
- Integrity management should be treated as a dynamic, continuous process, with risk-based inspections and periodic integrity reviews. Design basis assumptions should be verified over the riser life. Remnant fatigue life calculations prior to drilling, wear

logging during drilling and detailed inspection of riser joints prior to resuming production may be warranted.

IV.3.1.3 Current State of Knowledge

The risk-based methodology developed is still consistent with the riser integrity management chapter within the latest draft revision ISO 13628-12 / API RP 2RD. Some operators have

Industry momentum has been towards adopting a holistic approach to subsea integrity management. JIPs are underway to address SURF (Subsea, Umbilical, Riser and Flowline) Integrity Management.

IV.3.2 PROJECT NO. 540 – RISK ASSESSMENT OF SURFACE VS. SUBSURFACE BOP'S ON MOBILE OFFSHORE DRILLING UNITS

IV.3.2.1 Introduction

This report was produced for the MMS by The Offshore Technology Centre, Texas A&M University, and was issued in August 2006.

IV.3.2.1.1 Background

As water depth increases, the weight of conventional risers increases to a point that only a very few fifth generation floating rigs have the capability to drill in ultra-deep water. In an attempt to mitigate many of the problems associated with deepwater drilling, some operators have either considered using or have used surface Blowout Preventers (BOP's) with small diameter, high pressure risers in floating drilling operations. However, this is relatively new technology, and there is inherent risk in applying any new practices.

IV.3.2.1.2 Technical Scope

The aim of this project was to conduct a comparative risk assessment of the use of Surface Blowout Preventer Systems (SBOP's) and High Pressure Risers versus conventional Subsea Blowout Preventer Systems and drilling risers in the Gulf of Mexico Environment. This was achieved by focusing on the following tasks:

- A literature review to assess the state of the art in the use of surface BOPs on Mobile Offshore Drilling Units (MODUs);
- Perform an analysis of the frequency of riser failures for both conventional large diameter risers as well as the smaller diameter high pressure risers;
- Determine the proper risk evaluation tools that are available today and analyze the risk of utilizing a surface BOP system in deep water on a MODU;
- Determine the value and/or need for subsea shear rams shut-in device (SID) to be used with high pressure risers and surface BOP systems.

IV.3.2.1.3 Study Limitations

The final report is provided in the form of a M.S. thesis, which has not been peer reviewed. In addition, failure analysis was not performed by this study, but relied on work done by others; the data used may be affected by potential / probable non-reporting of minor failures or problems with equipment, Moreover, the various data sets used do not categorize failure consistently. All of these factors lead to uncertainties in the results of this study.

IV.3.2.2 Project Conclusions

IV.3.2.2.1 Key Conclusions and Results

The main conclusions of the report are:

- Risks of failure of both systems were assessed and compared. Reliability of surface BOPs was determined to be almost equal to the reliability of subsea BOP systems. This preliminary analysis suggests that the risk of failure of the entire system can be acceptable and operations can be carried out safely;
- A risk assessment has been shown to help understanding the high-pressure riser system through the identification of the critical components and their interaction with the overall pressure control equipment;
- Specific location and equipment planned to be used can drastically change the outcome of the overall risk analysis, since some areas are more susceptible than others to be hit by harsh metocean conditions;
- Results from the quantitative interpretation have a degree of uncertainty on their reliability, due to the nature of the dataset used. However, the work done allows the setting of upper and lower boundaries to understand the system behavior.

IV.3.2.2.2 OSER Goals

The project identified the elements that affect the reliability and risk of failure of Subsea BOP and riser systems. The reliability of Subsea BOP system was compared to that of Surface BOP system and was determined to be nearly equal. This effort is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.3.2.2.3 Recommendations

There are no specific recommendations made to the industry about the operation of BOP's, instead numerous suggestions for future work are made, which are:

- Future work should include secondary and tertiary failures to take into account chain events and their consequences;
- A more detailed analysis can be performed during the evaluation of a particular arrangement to determine the specific risk of the system;
- A study could be performed to evaluate the risk of installing a high-pressure riser and an SBOP in fixed deepwater production units like spars and tension leg platforms as an alternative for well control measurements;
- Awareness should be brought to the MMS regarding data quality to better assess risk analyses, as at present reported failures do not include a consequence level.

IV.3.2.3 Current State of Knowledge

Use of surface BOP in deepwater is one of the most promising trends. It is already a highly regarded enabler for driving well costs down in some deepwater applications; furthermore floating drilling rig-based surface BOP is more readily adapted to other emerging drilling methods than a conventional subsea BOP configuration. General industry focus has been to apply SBOP to third generation moored rigs, allowing them to operate in the deepwater environments dominated by fourth and fifth generation units.

Applications of the technology range from the benign environments of Southeast Asia to more demanding environments in Brazil and the Mediterranean with water depths also approaching 10,000 feet.

IV.4 DYNAMIC WELL CONTROL

IV.4.1 PROJECT NO. 582 – A PROBABILISTIC APPROACH TO RISK ASSESSMENT OF MANAGED PRESSURE DRILLING IN OFFSHORE DRILLING APPLICATIONS

IV.4.1.1 Introduction

This report was produced for the MMS by Stress Engineering Services Inc., and was issued in October 2008.

IV.4.1.1.1 Background

Based on studies sponsored by the American Petroleum Institute (API) and Minerals Management Service (MMS) prior to 2008, between 25% and 33% of all remaining undeveloped world reservoirs were unfavorable for use of conventional overbalanced drilling methods due in a large part to the increased likelihood of well control problems. Managed Pressure Drilling (MPD) is a tool that is intended to resolve and mitigate chronic drilling problems which contribute to non-productive time.

IV.4.1.1.2 Technical Scope

The main aim of this project was to study and develop MPD techniques used to dynamically control annular pressures and thus facilitate drilling of well that might have otherwise been economically unobtainable.

IV.4.1.1.3 Study Limitations

The information contained in this document is intended solely for the purpose of informing and guiding the staff and management of organizations charged with well design, well planning, and well construction. With respect to professional judgment and absolutes, Managed Pressure Drilling operations are application dependent. To this end the report should not be seen as an absolute, but as a guide.

IV.4.1.2 Project Conclusions

IV.4.1.2.1 Key Conclusions and Results

The Underbalanced Operations and Managed Pressure Drilling Committee of the International Association of Drilling Contractors have defined Managed Pressure Drilling as: an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.

- MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow down hole environmental limits, by proactively managing the annular hydraulic pressure profile;
- MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof;
- MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects.

The main conclusions of the project were:

- The drilling operation is often too large an area to focus on and so is divided into sections or nodes, typically centered on specific clusters of equipment or assemblies. A basic assessment needs to include the following within those sections: Deviation or Upset, Cause, Consequence, Severity, Frequency, Likelihood, Pure Risk, Safeguards and Controls, and Residual Risk;
- Managed Pressure Drilling applications are driven by the very narrow drilling margins between formation pore pressure and formation fracture pressure down hole;
- Objectives of Managed Pressure Drilling are to mitigate drilling hazards and increase drilling operations efficiencies by diminishing non-productive time (NPT). The operational drilling problems most associated with non-productive time include: Lost Circulation Stuck Pipe, Wellbore Instability, and Well Control Incidents;
- The vast majority of Managed Pressure Drilling is practiced while drilling in a closed vessel utilizing a Rotating Control Device (RCD) with at least one drill string Non-Return Valve, and a Drilling Choke Manifold;

- In many Managed Pressure Drilling applications, the wellbore is closed and able to tolerate pressure, this allows to better control the Bottom Hole Pressure with imposed backpressure from an incompressible fluid in addition to the hydrostatic pressure of the mud column and annular friction pressure;
- Managed Pressure Drilling must stay within the bounds of the well stability pressure curve, the pore pressure curve, and the fracture pressure curve;
- Reactive MPD uses Managed Pressure Drilling methods and/or equipment as a contingency to mitigate drilling problems as they arise;
- Proactive MPD uses Managed Pressure Drilling methods and/or equipment to actively control the annular pressure profile throughout the exposed wellbore. This approach utilizes the wide range of tools available to better control placement of casing seats with fewer casing strings, better control of mud density requirements and mud costs, and finer pressure control;
- By controlling the wellbore pressure profile, the risks of differential sticking and lost circulation diminish in frequency and magnitude; significantly reducing NPT, and thereby reducing safety incidents and costs associated with these risks;
- Clear methodology is given allowing for the identification and grading of the risks involved between drilling in a conventional, overbalanced system, compared to the drilling in a balanced, closed system, managed pressure environment.

IV.4.1.2.2 OSER Goals

Developing MPD techniques is necessary to facilitate drilling of wells that might otherwise be considered economically unfavorable. This effort is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.4.1.2.3 Recommendations

The report makes the following recommendations:

- The full time use of the rig choke manifold to control the annular pressure profile while drilling ahead is not recommended. The rig choke manifold should be reserved for well control incidents;
- Proactive MPD may require specialized well engineering design and planning. Rig crews may need additional guidance to supplement their well-control training.

IV.4.1.3 Current State of Knowledge

This study presents the latest knowledge in the area of Managed Pressure Drilling.

IV.4.2 PROJECT NO. 541 – APPLICATION OF DUAL GRADIENT TECHNOLOGY TO TOP HOLE DRILLING

IV.4.2.1 Introduction

This report was produced for the MMS by The Offshore Technology Centre, Texas A&M University, and was issued in November 2006.

IV.4.2.1.1 Background

Top hole drilling is faced with many challenges. Shallow subsurface geotechnical hazards including methane hydrates, shallow gas flows and shallow water hazards at the very least complicate the technical planning of a well and, at the worst, threaten the stability of the wellbore and the safety of the personnel.

Dual gradient technology may offer potential benefits in this field; if used in the top portion of the well, it would allow conductor and surface casing to be set deeper, and thus allow safer drilling of the intermediate hole. Some of the hazards of THDG can minimize include methane hydrates, shallow gas, and shallow water flows.

IV.4.2.1.2 Technical Scope

This study is the first phase of a three phase project into the application of dual gradient technology to top hole drilling (THDG). The aims of Phase I consisted of the following tasks:

- A literature review to analyze the benefits of THDG drilling over conventional riser and riserless (pump and dump) drilling;
- Determine the minimum equipment requirements for the THDG package;
- Define the mud and circulating system requirements to be used with the THDG package;
- Begin conceptual engineering design of the equipment required to conduct THDG drilling;
- Develop well control and drilling procedures for THDG drilling;

- Use preliminary results as a basis for soliciting further Industry Support for Phase II and III.

IV.4.2.1.3 Study Limitations

This work includes only conceptual design of equipment and a well control study conducted through computer simulation. Detailed equipment design, building and testing prototypes in the shop, refinement of well control and drilling procedures, and finally a field test on an actual well will be required to advance this concept to a proven system that can be confidently used by industry.

It is also worth noting the final report for Phase I is provided in the form of a M.S. thesis, which has not been peer reviewed.

IV.4.2.2 Project Conclusions

IV.4.2.2.1 Key Conclusions and Results

The main conclusions of the report are:

- A simplified design of the subsea pumping, and rotating equipment, and return riser which would allow sufficient circulation rates and pressure so that Top Hole Dual Gradient Drilling (THDGD) can be successfully implemented is conceivable;
- Dual gradient drilling technology has been designed, engineered and field tested for feasibility. This technology has been successfully applied to the top hole portion of a wellbore in a shallow water environment and in a deepwater environment after conductor and surface casing have been set;
- The riserless drilling simulator indicates that applying dual gradient technology to top hole drilling, when used in conjunction with a proper casing program, successfully navigates the narrow window between formation pore pressure and formation fracture pressure;
- The results of simulation also leads to the conclusion that the dual gradient technology applies safe well control methods while drilling the top hole portion and can control all three major shallow hazards (shallow gas, natural gas hydrates, and shallow water flows);
- Riserless Dual Gradient Top Hole Drilling can also bring other benefits such as: Rapid and accurate kick detection, Safe Well Control Procedures, Improved casing seats

and wellbore integrity, Reduced number of casing strings, Reduced overall costs, Prevention of methane hydrate formation, and Reduced environmental impact.

IV.4.2.2.2 OSER Goals

This report documented the results of the work done in Phase I of the study on Top Hole Dual Gradient Drilling (THDGD). The study concluded that the THDGD technology can be successfully implemented. This effort is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.4.2.2.3 Recommendations

The main recommendation of the report suggested that the next step in the development of this technology is to design and field test a system that can be applied to drilling the top hole portion of a wellbore in a deepwater environment.

IV.4.2.3 Current State of Knowledge

Dual gradient technology shows great promise for deep water drilling, potentially improving safety, quality, cost efficiency, and environmental impact. Convincing the industry end users (operators and service companies alike) of its merits through education and training is believed to be beneficial.

Chevron has taken the lead with a propriety initiative engineered to elevate a form of dual-gradient drilling, and hopes to have the industry's first fully integrated and commercialized dual-gradient drilling system actually operating in deepwater in the Gulf of Mexico by late 2011.

IV.4.3 PROJECT NO. 474 – EVALUATION OF SAFETY CONCERNS DURING WELL TESTING FROM OCS DRILLING RIGS

IV.4.3.1 Introduction

This report was produced for the MMS by Det Norske Veritas., and was issued in November 2004.

IV.4.3.1.1 Background

It is anticipated that flow testing activity of wells is likely to increase to provide more certainty than currently obtained by static testing alone. This report examined the impact on well test safety when moving into deeper waters, the increased possibility of encountering high pressure or high temperature conditions in deep gas wells, and also the possibility of increased arctic activity.

IV.4.3.1.2 Technical Scope

The objectives of the research in this report were to:

- Perform an initial fact finding by Det Norske Veritas (DNV) on Outer Continental Shelf (OCS) and worldwide practice, including involvement of major stakeholders, for well drilling;
- Perform a generic Structured What IF Technique (SWIFT)/Hazard Identification (HAZID) of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards;
- Development of Workshop Discussion Document based on the SWIFT/HAZID;
- Conduct Industry Workshop to solicit input to Guidance;
- Create Guidance draft based on workshop;
- Submit draft to industry/MMS for hearing;
- Finalize draft guidance and issue project report.

IV.4.3.1.3 Study Limitations

In many cases the guidance note produced does not propose specific solutions but may propose several alternatives, or may simply identify an area which the user needs to address using best engineering judgment.

IV.4.3.2 Project Conclusions

IV.4.3.2.1 Key Conclusions and Results

The main deliverable of the project is a Recommended Practice (RP) for Guidance on Safety of Well Testing. Some of the main conclusions of the project were:

- On the basis of the initial fact finding the SWIFT/HAZID was developed with a number of initial topics identified including; Deepwater Drilling, Testing from DP Vessels, Testing in Arctic Conditions, Shallow Water / Deep Gas Drilling, Offloading of Produced Oil, Quality of Equipment, Impact on the Drilling Unit, and Control of Operations;
- The SWIFT/HAZID provides a structured approach to identifying the hazards and current safeguards associated with typical well test operations, and potential future operations;
- Guidance has been created addressing key safety aspects of well testing on the OCS (in the form of the RP). The Guidance is based on current technology and industry practice. Development of the Guidance has been carried out based on a structured assessment of hazards associated with well testing, and is based on direction from the Workshop participants;
- MODU owners are required to have a safety management program in accordance with the International Maritime Organization's (IMO) International Safety Management (ISM) Code [13].

IV.4.3.2.2 OSER Goals

The project looked at safety related to well testing on the OCS. The final report provided guidance on a number of key areas with respect to flow testing of wells. This effort is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.4.3.2.3 Recommendations

As described in Section 1.2.1 the main deliverable of this project was the publication of a RP, which gives guidance and recommendations throughout for the safety of well testing. Some of the more pertinent recommendations are:

- Offshore operations, including well testing, should be covered by some form of safety management system;
- Contractors should consider requesting documentation relating to the safety management system of the operator;
- Operational instructions should be developed to define the actions to be taken when in or moving into the different zones of vessel positioning;

- When carrying out drilling operations in a known H_2S area the operator must create a contingency plan;
- An inspection and maintenance program should be developed which should follow; code recommendations; manufacturer recommendations; regulatory requirements; and operating experience.

IV.4.3.3 Current State of Knowledge

The report outlines Recommended Practices based on an extensive review of current industry practices and on input from representatives from the main parties concerned with well testing operations, Offshore Operators, Drilling Contractors, and Well Test Service Companies. To this end it could be stated that this document provides a clear overview of current practices in this area.

The International Maritime Organization (IMO) is expected to adopt an updated version of the IMO MODU Code in early 2010. Almost every section of the Code for the Design and Construction of Mobile Offshore Drilling Units or (MODU Code) has been affected. Major changes touch on areas such as fire safety, electrical equipment in hazardous areas, helidecks, means of access, single-compartment flooding and jacking system standards for jackups, and training. The new Code is expected to apply to units whose construction begins on or after 1 January 2012.

IV.4.4 PROJECT NO. 440 – DEVELOPMENT OF AN ASSESSMENT OF WELL CONTROL PROCEDURES FOR EXTENDED REACH AND MULTILATERAL WELLS UTILIZING COMPUTER SIMULATION

IV.4.4.1 Introduction

This report was produced for the MMS by the Offshore Technology Research Centre (OTRC), Texas A&M. University, and was issued in December 2004.

IV.4.4.1.1 Background

To date it is not fully understood which factors have a significant effect on choke pressures and gas-return rates for various kick scenarios. It is also required to further develop an understanding of the art of well control for extended reach and multilateral wells.

IV.4.4.1.2 Technical Scope

The objectives of the research in this report were:

- To perform an extensive simulation study of vertical, directional, horizontal, and Extended Reach Drilling (ERD) wells. Based on the simulation, study recommendations are to be made to improve well control for situations that warrant improvement, especially for ERD wells. A simulator will be used to validate the procedures;
- To accurately model the kick-removal circulation procedure for horizontal wells at varying inclinations above and below true horizontal.

IV.4.4.1.3 Study Limitations

The main deliverables of this report are in the form of two Theses, for the degree of Master of Science. It is not known if these theses have been successfully peer reviewed, and thus the validity of the conclusions and recommendations may be questionable.

Recommendations to improve well control for any situations that warrant improvement, especially for the extended reach and multilateral wells (Task 4 of the proposal) have not been made, and are not included in the project. The introduction of the report states that this task is outstanding at the time of issuing this report.

IV.4.4.2 Project Conclusions

IV.4.4.2.1 Key Conclusions and Results

The main conclusions of the project were:

- An increase in kick size causes an increase in the maximum choke pressure, and the maximum choke pressure increases with True Vertical Depth (TVD) of the well;
- Minimal difference in maximum choke pressure for kick sizes of 100 and 200 barrels are observed; with significant increase observed for pressures from 10 bbl to 50 bbl;
- A considerable increase in choke pressure is observed with an increase in water depth due to the change in depth of the hydrostatic column, similar to when increasing TVD of a well;

- High kick intensity results in higher choke pressure due to an increase in bottom hole pressure. For larger water depths the pressure gradients are more severe as the formation overpressure increases with water depth and kick intensity.

The main conclusions from the simulation analysis section of the report were:

- Difficulty in removing gas kicks may be encountered in wellbores with inclination greater than horizontal. The higher the inclination, the more pronounced this effect;
- As annular area increases, higher circulation rates are needed to obtain the needed annular velocity for efficient kick removal. For water as a circulating fluid, an annular velocity of 3.4 ft/sec is recommended;
- Lower kick-removal annular velocities may be obtained by altering mud properties. Fluid density slightly increases kick removal, but higher effective viscosity is the overriding parameter;
- Increasing relative roughness slightly increases kick-removal efficiency;
- Bubble, slug, and stratified flow are all found to be present in the kick-removal process. Slug and bubble flow are the most efficient at transporting the gas kick.

IV.4.4.2.2 OSER Goals

The project assessed and developed well control procedures for extended reach and multilateral wells utilizing computer simulation. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.4.4.2.3 Recommendations

The report makes the following recommendations:

- Once a kick is detected and confirmed, the well should be shut-in until the pressures have stabilized, and circulation started immediately using the Driller's Method. If there are problems with hole cleaning, it is best to resume circulating as soon as possible;
- Start circulating at a high rate for a short time to remove gas from the horizontal section of the wellbore. Once the choke pressure starts to increase rapidly, slow down the pumps and continue the circulation with a kill rate 1/3 to 1/2 of the rate in drilling mode;

- If various circulation rates are used, pressure decline schedules have to be made for each circulation rate, due to the friction pressure loss which increases with higher circulation rate;
- Horizontal sections at inclinations greater than horizontal can have a negative effect. These trajectories are often unavoidable in mountainous or uneven terrain, lease boundaries, and location of producing formation. However, these inclinations should be avoided wherever possible;
- Hole size and completion methods should be considered when planning an inclined horizontal section;
- Circulation should occur at an annular velocity to efficiently displace the kick. Once the kick influx reaches the vertical section and the choke pressure begins to rise, the circulation rate may be decreased.

IV.4.4.3 Current State of Knowledge

To expand the knowledge in this area, research is being conducted on the following topics:

- Investigation of kick scenarios for multilateral wells. This had started at Texas A&M University at the time of writing of this report;
- Investigation of the effects of fluid properties to include pumping slugs of viscous and oil-based fluids, and considering the effects of gas kicks going into solution.

IV.5 CONDUCTOR CASE INTEGRITY

IV.5.1 PROJECT NO. 495 – RISK ASSESSMENT AND EVALUATION OF THE CONDUCTOR PIPE SETTING DEPTH ON SHALLOW WATER DEPTHS

IV.5.1.1 Introduction

This report was produced for the MMS by Texas A&M University / TEES, and was issued in September 2006.

IV.5.1.1.1 Background

Leading oil and gas corporations have placed deliberate emphasis on marketing their shallow water and economically volatile assets to small independent oil and gas companies. Due to recent technological advancements in production systems, it is economically feasible for these small independent oil and gas companies to pursue these so called "unwanted" assets as part of their own portfolio.

Early drilling studies and guidelines have mentioned casing design and well control issues. However, they have neglected situations where upward fluid migration can lead to abnormally pressured shallow formations, especially in a developed field. Even in situations where there has not been any artificial charging of shallow formations, selection of conductor and surface casing setting depths has, in the past, been based more on tradition than sound engineering practices.

IV.5.1.1.2 Technical Scope

The aim of this project was to conduct a Risk Assessment and evaluation of the conductor pipe setting depth on shallow water wells and to write guidelines as to how to select conductor setting depths. This was achieved by completing the following tasks:

- Literature Review and Analysis of the Strength of Shallow Water Sediments;
- Evaluation of the Effect of Gas Migration into Shallow Water Sediments on Conductor Casing Setting Depths;
- Document the results of these tasks in a final report.

IV.5.1.1.3 Study Limitations

The main deliverable of this study was a report in the form of a Master's of Science thesis, and as such may be perceived to be academic in nature.

IV.5.1.2 Project Conclusions

IV.5.1.2.1 Key Conclusions and Results

The main conclusions of the project were:

- Most Gulf of Mexico (GOM) blowouts were the result of shallow gas. Although blowouts are the worst problem that can be encountered during drilling operations, other hazards, such as mud volcanoes, gas hydrates, permafrost etc., can be encountered;
- In order to avoid these shallow hazards, a thorough shallow hazard study and analysis of shallow seismic data must be conducted prior to any drilling in a new area. If shallow gas and hydrocarbon seepages are discovered, consideration of placing the surface location of any wildcat wells and/or platforms away from these hazards should be made;
- Scattering of the fracture pressure of shallow marine sediments in the GOM strongly indicates that casing depth for conductor casing and surface casing cannot be based on tradition. Conductor and surface casing depths must be determined for each individual well/platform;
- The only way to ensure the formation fracture pressure is sufficient, and the cement bond between cement and casing and cement and formation is intact, is to perform a Leak-off Test (LOT) on the conductor shoe;
- The seismic data, when available, should be used in conjunction with soil boring data for generating the Poisson's ratio and estimating bore-pressure in the Shallow Marine Sediments (SMS) of the GOM; hence a better analysis can be made using mathematical relationships;
- Operational considerations and engineering economics should be the key elements for the selection of the conductor setting depth in the shallow water of GOM and well control contingency plans;
- The validity for the rejection of the "rule of the thumb" methodology for the conductor setting depth has been demonstrated. An engineering theories and

calculation approach for the conductor setting depth estimation in terms of pressure and stress predictions should be applied;

- A design based on the well control aspects is found to be the safest approach for offshore wells. A safe design based on the optimum lengths of conductor and surface casing would enable the operator to handle possible formation kicks;
- For the well control contingency a Blowout Preventer (BOP) with the ability to divert formation fluids at surface should be considered when drilling the open hole of the conductor section.

IV.5.1.2.2 OSER Goals

The project assessed the risk associated with conductor pipe setting depth on shallow water wells. Evaluation of the effect of gas migration into shallow water sediments on Conductor Casing Setting Depths was also conducted. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.5.1.2.3 Recommendations

The report makes the following recommendations:

- Completion of a new methodology of interpreting non-linear LOT in shallow marine sediments should be completed;
- An operator should consider a thorough risk assessment of each well based on accurate prediction of formation fracture pressure and formation pressure as well as conducing a LOT on the casing seat to determine the kick tolerance on a conventional well kill.

IV.5.1.3 Current State of Knowledge

Work is being conducted at Texas A&M University on a new way to plot leak off data that is hoped will result in a much improved non-linear LOT interpretation. When conclusive results are available the authors will issue a supplement to this report.

Research of the pressure to define the casing setting depth as a function of fracture gradient is being conducted to develop a simple design method which will be made available to the industry upon completion.

IV.5.2 PROJECT NO. 426 – LONG TERM INTEGRITY OF DEEP WATER CEMENT SYSTEMS

IV.5.2.1 Introduction

These reports were produced for the MMS by Cementing Solutions, Inc. (CSI), and were issued between April 2002 and September 2004.

IV.5.2.1.1 Background

Significant effort has been devoted to development of cement compositions to alleviate shallow water flow, a potential source of severe operational and economic consequences. However, the long-term integrity of the seal provided by these special compositions has not been evaluated. 25-30% of wells are estimated to have annular pressure problems; this can be the result of a number of factors, but cementing is one of the primary root causes.

IV.5.2.1.2 Technical Scope

The overall objective of this project was to evaluate the ability of cement compositions to provide well integrity and zonal isolation through zones in which subsidence, compaction, and excessive stresses can be long-term problems. The project primarily focused on deepwater applications, but general applications were also examined.

CSI study focused on the measurement and correlation of cement mechanical properties, of mechanical integrity of a cemented annulus, and on mathematical simulation of stresses induced in a cemented annulus.

IV.5.2.1.3 Study Limitations

Simplifications were used to analyze the various cements seal capacity, in order to address the difficulty of stress measurement resulting from the non-homogeneous composite nature of the system. Correlating total energy input rather than stress to ultimate cement failure may be acceptable to compare behavior, but only if cements are used in very similar conditions (i.e. formation, geometry). A more proper correlation would consider only the energy applied to the slurry itself. Furthermore, data are too limited to allow extending these results to field geometries with confidence.

Assumptions have been made for the mathematical modeling of cement systems that may not be representative of the actual field situation (e.g., system modeled using linear elastic theory, composite system to retain continuity at interfaces).

IV.5.2.2 Project Conclusions

IV.5.2.2.1 Key Conclusions and Results

Based on a literature review and on Participants opinions as to the factors that affect the integrity of the annular seal, a list of mechanical properties and mechanical integrity failure modes to test was made out.

Research was conducted in order to determine which laboratory methods should be used to establish the cement's key properties, leading in some cases to development of new testing methods (e.g. regarding testing of shear bond strength, cement's capability to maintain its seal).

Testing has been carried out for soft, intermediate and hard formations with the four main cement systems, i.e. Bead, Foam, Neat and Latex systems. Cyclic loading conditions (Pressure & Temperature) were applied for integrity testing.

Mechanical Properties Testing Key Results

Significant variations in Poisson's ratio have been observed with varying stress rate. Loading samples at a faster rate results in higher values. Another factor was revealed to be the presence of entrained air, as increased porosity appears to lower measured values.

Strain testing data indicates larger strains for low density compositions than for normal density cements. More significant increases were observed for foam than for the other compositions. Strain versus time curves show that both foam and bead cement exhibit larger increasing strain with time under stress.

Mechanical Integrity Testing Key Results

Cement formulations conditioned in high restraint conditions (pipe in hard formation) resulted in higher shear bond strengths and withheld annular seals more successfully as compared to formulations conditioned in low restraint simulations (pipe in soft formation).

The amount of energy usually required to induce cement sheath failure increases with the competence of the formation. Exceptions were observed in the case of Bead systems and temperature loading. The explanation may reside in the superior insulating properties of the beads, reducing the importance of formation competence within limits. Bead cements performed very well in all the testing. This may support the use of beads in cases that would traditionally have indicated foam.

In all cases, the amount of temperature energy required to initiate failure is much lower than the pressure energy to failure. This may be due the destructive effects of matrix water expansion with temperature. Foam cement faired best in pressure cycling and worst in temperature cycling.

Numerical Simulation

Results of numerical modeling of stresses and strains showed that the importance of material properties of the cement increases as formation strength decreases: significant stress results from loading samples in soft-formations cases, while stress in the cemented annulus is greatly reduced if there is a strong formation backing.

Mathematical modeling resulted in a method to quantify laboratory test results and to scale them to field conditions.

IV.5.2.2.2 OSER Goals

The project focused on assessing long term integrity of deep water cement system with emphasis on deep water applications. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.5.2.2.3 Recommendations

- In order to extend the analysis to a broader range of real-well conditions, more precise measurements and additional data points are required for confirmation of trends; this implies further work to understand the energy absorption of the various wellbore components, and testing of additional cement and formation types.
- It is recommended to develop a decision support system, for optimizing cement selection based on performance in various well conditions.

IV.5.2.3 Current State of Knowledge

The challenge of HPHT drilling conditions keeps driving researches to find the ideal cement for durable annular seals. This has lead to solutions such as high-performance lightweight cementing systems based on hollow-microsphere additive material [14] or to epoxy resin based sealants [15].

IV.6 BOP COMPONENTS AND SECONDARY INTERVENTION SYSTEMS

IV.6.1 PROJECT NO. 463 – EVALUATION OF SHEAR RAM CAPABILITIES

IV.6.1.1 Introduction

This report was produced for the MMS by West Engineering Services Inc., and was issued in September 2004. It represents the continuation of TA&R Project No. 455.

IV.6.1.1.1 Background

For obvious reasons, a BOP system should be capable of shearing any pipe planned for use in the drilling program. Drilling technology has changed over the years, and preliminary study on the subject has shown that current models, specifications, and testing procedures may not be adapted any more.

IV.6.1.1.2 Technical Scope

This study reviews existing shear data provided by manufacturers in an attempt to better understand the factors governing shear ram capabilities, considering drill pipe mechanical properties (yield strength, ultimate strength, and ductility) and examining the shear force equation derived from the Distortion Energy Theory.

IV.6.1.1.3 Study Limitations

Differences in drill pipe mechanical properties recorded by the manufacturers complicated analysis and comparison of shearing data. In particular, scarcity of dataset may be responsible for some anomalous results when attempting correlation of ductility indicators.

- Following the opinion of one BOP manufacturer, the study assumes that the BOP size does not matter, i.e. that shearing with systems of different sizes but of same ram type will require the same force. However, there is some question as to whether this is true.
- Data received by the authors for this study primarily included shear rams having both blades "V" shaped. Other types were therefore excluded from statistical consideration in this study.

IV.6.1.2 Project Conclusions

IV.6.1.2.1 Key Conclusions and Results

Predicting the shear point and adding a safety factor are important steps in assessing shear capabilities; manufacturers are currently adjusting the Distortion Energy Theory in order to do both with one calculation. While giving reasonable results, this method has not been found to consistently predict the highest actual shear forces.

The study developed equations that provide a better model of the available shear data than those used by the BOP manufacturers, using indicators both related to Distortion Energy Theory (i.e. based on yield strength) and to ductility of pipe material.

- Both Charpy values and Elongation % are indicators of ductility / brittleness of a material. However, only minimal correlation between these two parameters could be observed. This anomaly may have been the result of the limited quantity of shear data having both Charpy and Elongation % information.
- Furthermore, using Charpy values to compare data was made difficult by the fact that these values were reported at different temperatures and for different size samples. Elongation %, which is deduced from a standardized test, was therefore used in trying to determine a possible shear force equation
- Statistical distribution of shear points for three types of drill pipes was worked out and regression analyses was used with yield strength and Elongation % as independent variables, producing best fit equations for general case (i.e. all data sets) and for individual drill pipe types. In general, the formula used is of the form:

$$Y = A \cdot X_1 + B \cdot X_2 + 2 \cdot StErr + C$$

With Y = Calculated fit shear force (Kips)

X_1 = Shear as predicted by Energy Distortion Theory (Kips)

X_2 = Elongation %

StErr = Standard Error of Estimate

A, B, C = constants developed from Regression Analysis

- An empirical shear force formula was also proposed for cases where only yield strength of the material is available for the drill pipe in use.

IV.6.1.2.2 OSER Goals

The critical safety and environmental nature of the shear ram function prompted this study to more clearly understand and define operating limits of equipment performing this task. Shear rams are often the last line of defense and must be available and capable when needed. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.6.1.2.3 Recommendations

The following recommendations are made:

An industry wide data base of shear forces/pressures should be established. Shear data available is lacking in complete detail and more information is needed to increase the viability of the equations presented in this study.

The data should be gathered in a consistent manner from shear tests performed to a prescribed procedure. The data for the drill pipe should be, at a minimum: pipe OD and wall thickness, material grade, actual yield strength, actual ultimate strength, Charpy impact at a standardized temperature and Elongation %.

The MMS could provide encouragement to industry participants to share such data and suggest similar test methods and procedures

There are several different ways to refer to pipe weight designations and confusion can result from this. Referring to the drill pipe by the actual plain wall thickness instead of using other designations would be beneficial for answering shearing questions.

In order to obtain a standardized prediction of shear force requirements, develop a simple Excel spreadsheet requiring minimal input by the user. Only simple, available data would be input with the output being a risk adjusted shear force prediction.

IV.6.1.3 Current State of Knowledge

The evolution of drilling technology over the years has effects on BOP design and shearing capabilities requirements. Current study has focused on some aspects of the problem – i.e. shear force requirement prediction based on pipe material properties – based on the few data sets made available. Other factors such as shear rams configuration and additional pressures resulting from operating conditions are also known to affect shearing capabilities. A more global, data review campaign that would allow defining / refining and validating comprehensive models and equations is still lacking.

IV.6.2 PROJECT NO. 455 – REVIEW OF SHEAR RAM CAPABILITIES

IV.6.2.1 Introduction

This report was produced for the MMS by West Engineering Services Inc., and was issued in December 2002.

IV.6.2.1.1 Background

For obvious reasons, a BOP system should be capable of shearing any pipe planned for use in the drilling program. Drill pipe technology has improved over the years. The increase in drillpipe sizing as well as improved metallurgies, while benefiting the industry in many respects, detrimentally affects the ability to shear pipe should this last means of securing a well be necessary. Adding to the above concern is the fact that equations used to estimate the required shearing pressure do not include all pertinent variables.

IV.6.2.1.2 Technical Scope

This mini-study examines shear rams capabilities data from drilling rigs that WEST Engineering Services, Inc. had experience with during a recent round of upgrades. Purpose of the project was to obtain a snapshot of actual shearing capabilities of rigs that are working on the OCS (i.e. subsea BOP's). In addition, a review of API Specification 16A [7] requirements and procedure is also presented.

IV.6.2.1.3 Study Limitations

The principal limitation of this study lies in the limited data set: only seven rigs were tested, one of which had insufficient data to draw a definitive conclusion; note that as many rigs opted not to test their shear ram capabilities.

IV.6.2.2 Project Conclusions

IV.6.2.2.1 Key Conclusions and Results

The main conclusions of the report are:

- API Specification 16A – 2nd Edition [16] address pipes that are not representative of modern drillpipes; as a result, meeting its requirements do not guarantee that a rig is operating in a prudent or safe manner.
- More specific guidelines would ensure more uniform testing and results that are closer to actual shear values; furthermore, additional factors related to operating conditions should be considered for more realistic assessment of capabilities.
- The total effect of additive pressures resulting from operating conditions can result in an increase of the required shearing pressure in the order of 20% or more.
- Of the seven tested, five successfully sheared and sealed (71%) based on shop testing only.
- If operational considerations of the initial drilling program were accounted for, which could be done only for six of the rigs given available data, shearing success dropped to 50%.
- Based on the results obtained, two of the rigs modified their equipment to enable shearing and sealing on the drill pipe for their program.
- At least some of the rigs in operation have not considered critical issues necessary to ensure that their shear rams will shear the drillpipe and seal the wellbore.

IV.6.2.2.2 OSER Goals

The critical safety and environmental nature of the shear ram function prompted this study to more clearly understand and define operating limits of equipment performing this task. Shear rams are often the last line of defense and must be available and capable when needed. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

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IV.6.2.2.3 Recommendations

The following recommendations are made:

- Equations used to estimate the required shearing pressure should include all pertinent variables, including effects such as hydrostatic effects, work hardening, etc. Such factors should be better understood before a final recommendation can be established.
- API Specifications related to shear ram testing should be revised and improved to ensure more uniform testing and more realistic results.
- Additional rigs should see their shear rams capabilities tested, so as to extend the available database and to confirm methods of estimating shear pressure for the full range of pipe available today
- People involved with drilling operations should be better educated about this potential issue.

IV.6.2.3 Current State of Knowledge

Another study completed this review of shear ram capabilities, gathering further data and attempting to predict shear force requirement based on pipe material properties. However, a larger-scale testing / data review campaign that would allow defining / refining and validating comprehensive models and equations is still lacking.

IV.6.3 PROJECT NO. 431 – EVALUATION OF SECONDARY INTERVENTION METHODS IN WELL CONTROL

IV.6.3.1 Introduction

This report was produced for the MMS by West Engineering Services Inc., and was issued in March 2003.

IV.6.3.1.1 Background

Secondary intervention can be defined as an alternate means to operate BOP (blowout preventer) functions in the event of total loss of the primary control system or to assist personnel during incidents of imminent equipment failure or well control problems. These systems can be completely independent and separate or utilize components of the primary BOP control system.

The design, capabilities, and early experiences of various secondary BOP control intervention systems as recently installed on twenty new build and upgraded drilling rigs were in need of review.

IV.6.3.1.2 Technical Scope

The aim of the study was to provide a review of the design and capabilities of various secondary BOP intervention systems as recently installed on new built and significantly upgraded drilling rigs. In addition, it identifies the best systems and practices currently in use as well as opportunities that could enhance the effectiveness of these systems.

IV.6.3.1.3 Study Limitations

This study reports on assessments conducted by WEST Engineering which was supplemented by discussions with manufacturers of secondary intervention system, operators, and drilling contractors and review of design documents. As such the conclusions and recommendations are subjective.

IV.6.3.2 Project Conclusions

IV.6.3.2.1 Key Conclusions and Results

The main conclusions of the project were:

- Any system designed to shear pipe must be demonstrated to be capable of shearing the pipe;
- The placement of the drill pipe tool when the shear activity occurs is critical;
- If a secondary intervention system is added to an existing system, a risk analysis should be performed to ensure the design is compatible and functionality optimal;
- MMS guidance should be provided concerning arming of secondary intervention systems;

- ROV capability as a means of secondary intervention should include the ability to utilize subsea accumulators as a supply source in order to ensure the designated functions can be performed in the API recommended time;
- Monitoring of the status of secondary intervention systems is desirable;
- Acoustic systems are not recommended because they tend to be very costly, and there is insufficient data available on system reliability in the presence of a mud or gas plume. However, acoustic communication in the form of verification of system status and remote arming should be considered.

IV.6.3.2.2 OSER Goals

Secondary intervention systems are of the utmost importance and offer the last line of defense in preventing and/or minimizing environmental and safety incidents. An advanced knowledge of secondary intervention systems and their shortfalls could prevent an environmental event, human injuries, and/or loss of lives. This is inline with the goals of the OSER program which is concerned with the evaluation of the technological challenges associated with the offshore energy operations.

IV.6.3.2.3 Recommendations

The report makes the following recommendations:

- For rigs with a multiplex BOP control system operating in DP mode, the recommended systems is a deadman system;
- The variety and permutations of secondary systems are significant. Evaluation and use of the system(s) installed on a given rig requires an understanding of the failure modes, which it can mitigate. Risk/reward analyses can then determine adequacy of a rig's system for a particular drilling program;
- The addition of an auto shear circuit is recommended to provide the automatic closure of the well in the event another cause accidentally unlatches the Lower Marine Riser Package (LMRP).

IV.6.3.3 Current State of Knowledge

This report provides an overview of secondary intervention systems that were recently installed or upgraded circa 2004, outlining interpretation of associated standards and identifying best practices for these systems. To date no further large study has been widely published that follows in from this work. However, providers of acoustic systems claim that the acoustic technologies have enhanced since the date of the study and that a re-evaluation may be warranted.

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