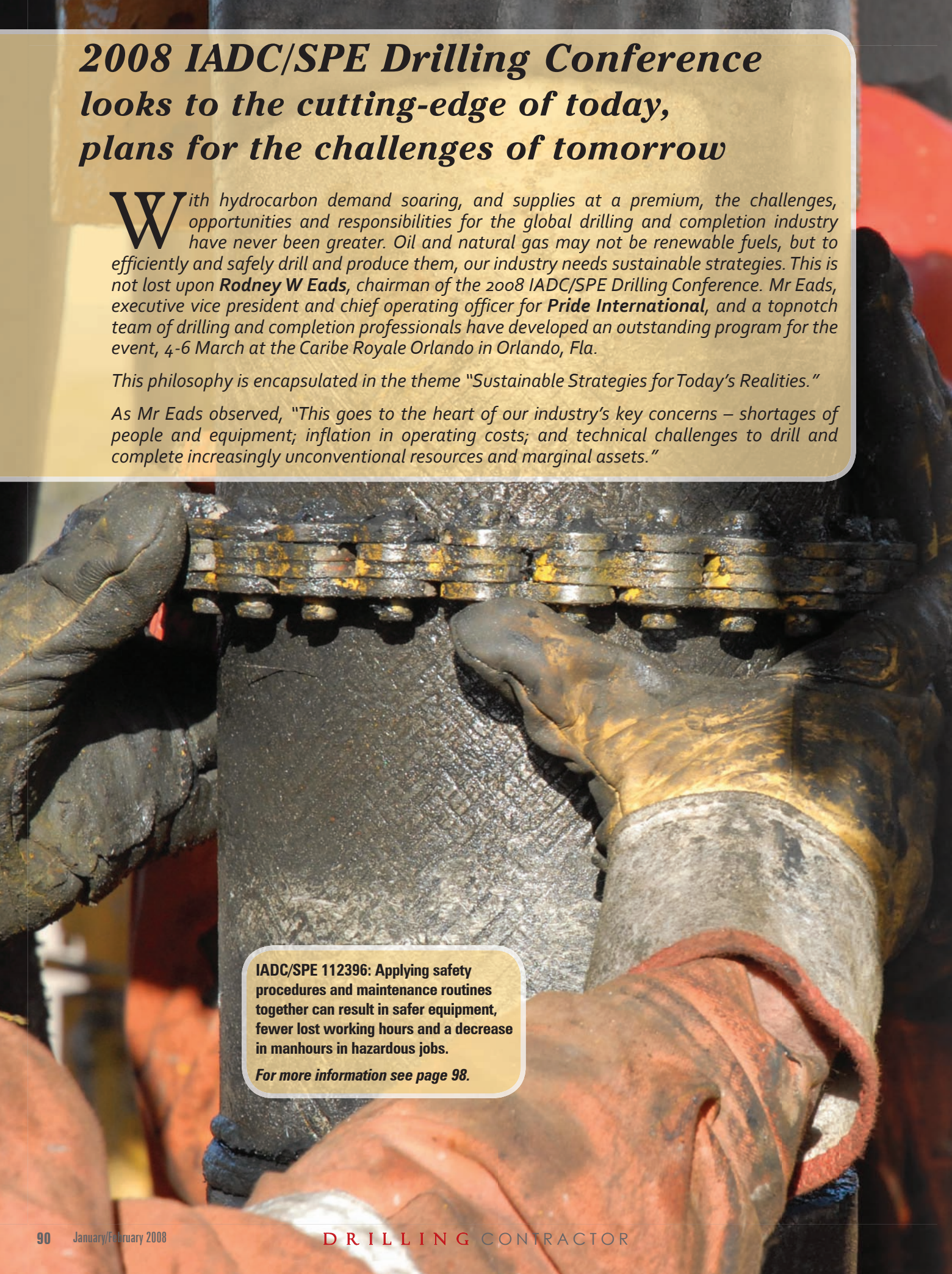


2008 IADC/SPE Drilling Conference looks to the cutting-edge of today, plans for the challenges of tomorrow

With hydrocarbon demand soaring, and supplies at a premium, the challenges, opportunities and responsibilities for the global drilling and completion industry have never been greater. Oil and natural gas may not be renewable fuels, but to efficiently and safely drill and produce them, our industry needs sustainable strategies. This is not lost upon **Rodney W Eads**, chairman of the 2008 IADC/SPE Drilling Conference. Mr Eads, executive vice president and chief operating officer for **Pride International**, and a topnotch team of drilling and completion professionals have developed an outstanding program for the event, 4-6 March at the Caribe Royale Orlando in Orlando, Fla.

This philosophy is encapsulated in the theme "Sustainable Strategies for Today's Realities."

As Mr Eads observed, "This goes to the heart of our industry's key concerns – shortages of people and equipment; inflation in operating costs; and technical challenges to drill and complete increasingly unconventional resources and marginal assets."



IADC/SPE 112396: Applying safety procedures and maintenance routines together can result in safer equipment, fewer lost working hours and a decrease in manhours in hazardous jobs.

For more information see page 98.



NINETY TECHNICAL PAPERS span diverse drilling and completion topics – fluid technology, completions, performance drilling, drill bits, tubulars, HSE, rig equipment, deep-water operations, directional and extended-reach drilling, telemetry, zonal isolation, managed pressure and underbalanced operations, casing while drilling and more.

In addition, three thought-provoking plenary sessions will offer new ideas to pressing problems. “Voting pads” will be used to poll the audience for their reaction to the topics of the day.

The opening day plenary is “Operating Cost: Validation, Consequences and Solutions.” Moderated by **Paul Goodfellow**, regional wells manager-Americas, **Shell E&P Americas**, the session will explore the key issues of service costs, downtime, high dayrates, and shortages of equipment, services and equipment.

The plenary will discuss the impact of these cost increases throughout the supply chain. Is our industry concerned simply with costs or does the service quality level associated with those costs have a more significant impact? The panel will also present and discuss the broader issues that have influenced the increase in costs for drilling, producing, construction, services and manpower. The role of technology will also be reviewed.

Confirmed panelists are:

- **William Coates**, president North America, **Schlumberger**;
- **Michael Holly**, executive vice president, **Celerant Consulting**;
- **Stuart Ferguson**, senior VP & chief technology officer, **Weatherford International**;
- **Kevin Neveu**, CEO, **Precision Drilling Corporation**;
- **Kevin Carey**, general manager - deepwater & complex wells, **Chevron**.

The second-day plenary will explore “Technology: The Key to Finding and Producing Difficult Hydrocarbons.” The moderator is **Charlie Williams**, chief scientist-well engineering, production technology for **Shell International E&P Technology**.

Technology has been the backbone and heart of the drilling and completions industry’s ability to find and produce oil and gas in ever more difficult places and circumstances. The industry is achieving tasks today that 20 years ago it could not even imagine accomplishing. However, the challenges in finding and producing hydrocarbons today have become even more difficult both technically and economically. This session

will discuss the use of technology in discovering and producing difficult to find hydrocarbons.

Confirmed panelists are:

- **Hesketh Streeter**, vice president - energy consulting for Latin America, **Wood Mackenzie**;
- **Gregers Kudsk**, vice president, engineering and projects, **Maersk Contractors**;
- **Derek Mathieson**, president and CEO, **WellDynamics**;
- **Mark B Puckett**, president, **Chevron Energy Technology Company**;
- **Merrilee C Gordon**, vice president - **Upstream Shell Global Solutions**.

The final-day plenary will look to tomorrow: “Roadmap to the Future: People and Processes.” Moderated by **James F “Ford” Brett**, president, **PetroSkills Oil & Gas Consultants International**, the panel asks what processes and methods will we evolve to sustain growth to 2015, and how can we accelerate the learning curve for the thousands of necessary new hires.

In the next three years, more than 120 new offshore rigs will join the drilling fleet, with average personnel requirements of around 200 to operate and support each rig. The estimate for new land rigs worldwide in 2007 was around 750. Meanwhile, our most experienced people are crossing the threshold to retirement. The most experienced are often promoted to management and mentor positions as our employee base grows, with an often-adverse affect on front-line efficiency, as the average experience level drops.

Confirmed panelists are:

- **Ross Richardson**, director, HR, HSEQ and training, **KCA Deutag**;
- **Didier Charreton**, vice president human resources – BHI Corporate, **Baker Hughes**;
- **Walter A F Simpson**, general manager, operations and well engineering, **BG Group**.

“A lot has changed in the global drilling industry in 25 years, and a lot has stayed the same,” Mr Eads remarked. “One of the constants is that this industry and the people in it are always on the cutting edge of invention. We seek to drill wells faster, more efficiently and with an increased emphasis on safety and protecting the environment. We look for ways through our drilling to minimize damage to the formation and to improve productivity and recoverability.”

A link with more information is available at www.iadc.org/conferences.htm. ♦

Technical Session: Performance Drilling

IADC/SPE 112765

Barnett Shale Drilling and Geological Complexities — Advanced Technologies Provide the Solution. S.S. Janwadkar, S. Morris, M. Thomas, Baker Hughes; G. Jackson, G.K. Roberts, D. Fortenberry, M. Kramer, D. Dennie, Devon Energy.

The Barnett Shale field of North Texas is the most prolific and fastest-growing natural gas field in North America. It has a multi-trillion cu ft equivalent upside potential, but efficient extraction of natural gas from the Barnett shale poses drilling and geological challenges. Geological complexity requires precise placement and drilling of the well as per the directional well plan.

Major challenges that affected efficiency were down-hole drill string dynamics, high torque and drag, hole pack-offs and loss circulation. Engineers determined that early detection of downhole problems, such as high vibrations, poor hole cleaning and high equivalent circulating densities, were key to improving drilling performance. Bed boundary detection and formation dip determination were absolutely essential for precise placement of the well as per the directional well plan.

To overcome these challenges, state-of-the-art LWD tools were run to acquire real-time data and images. Real-time data acquired was inclination/azimuth close to the bit, bore/annular pressure and vibration/stick slip. Drilling data gathered real time was crucial to detect and eliminate potential drilling problems. Real-time geological data transmitted to surface was formation resistivity and azimuthal gamma ray measurements. High-resolution images were developed from real-time azimuthal gamma ray measurements and used to precisely detect bed boundaries and estimate formation dips accurately.

This strategy has been implemented to drill several wells in the Barnett Shale with excellent results. Advanced technologies have helped in significantly improving drilling performance and in precise placement of the wellbore. The rotating hours have reduced from 330 to 165 hours per well. A 48.39% reduction in days required (31.2 to 16.1 days per well) from spud to rig release has been realized.

IADC/SPE 111874

Drilling Difficult Formations Efficiently with the Use of an Anti Stall Tool. K.S. Selnes, StatoilHydro; C. Clemmensen, Halliburton; N. Reimers, Tomax.

The Anti Stall Tool (AST) is a mechanical downhole device that aims to adjust the drilling torque automatically in real time. Originally the tool was developed for coiled tubing applications, where it has proven its ability in successful reduction of vibrations, motor stalls, equipment failures and general wear and the increase in ROP and run length. The tool has been developed further to be used in rotary drilling. The goal was to remove cutter-induced torque variations and its harmful effects. The tools were made for a variety of hole sizes. They were run both in test wells and field trials in different configurations in various bottomhole assemblies with PDC bits and reamers.

The tool has been used in four runs in test wells and 34 runs in 14 wells on regular jobs in the North Sea and Norwegian Sea. The paper describes, both from theory and based on field experience, how the bit-induced torque fluctuations are decreased and how BHA damage is prevented to increase run lengths. The drill string connection over torque is eliminated and high effective drilling torque is ensured to increase the ROP.

IADC/SPE 112744

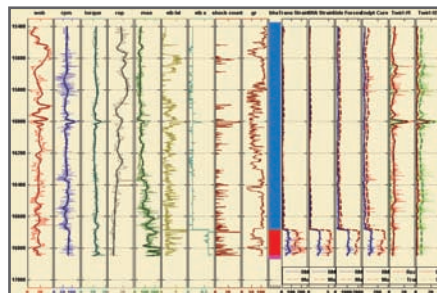
Offshore Field Test of a New Integrated System for Real-Time Optimization of the Drilling Process. F.P. Iversen, E. Cayeux, E.W. Dvergnes, R. Ervik, M. Byrkjeland, International Research Institute of Stavanger; M. Welmer, National Oilwell Varco; A. Torsvoll, M. Balov, E. Haugstad, StatoilHydro; A. Merlo, ENI.

A North Sea field test has been performed of a new drilling control system for real-time optimization and automation control. The system applies continuously updated drilling process models. The aim of the field test was to demonstrate that the incorporation of real-time calibrated process models in drilling control can make the drilling process more reliable, increase efficiency and improve safety for the drilling crew and with regards to well control. The system performs continuous optimization of operational parameters using calibrated process models. Safe operational windows are calculated, and operational sequences are automatically optimized through forward model simulations. The results are applied to machine control in real time, providing process safeguards and increasing process efficiency.

The paper will give a thorough description of the preparations and running of the field test. The test results are evaluated based on success criteria developed prior to the test in cooperation with field operator and drilling contractors. The implications for the work organization are also discussed, particularly in relation to control of data input, decision making and responsibility. This technology will allow for direct integration of the know-how and best current practices into the drilling control system. Automated procedures and tests will give improved control of well conditions. Direct integration of process models will enable safe optimization in the short time span. And coupling the drilling control system to remote input will enable optimization in the long time span.



IADC/SPE 111874: The Anti Stall Tool is a mechanical downhole device that aims to adjust the drilling torque automatically in real time.



IADC/SPE 112650: A modeling tool has been developed that enables drilling engineers to design vibration-resistant BHAs, given tool placement constraints and desired directional objectives.

IADC/SPE 112650

Drilling Vibrations Modeling and Field Validation. J.R. Bailey, E. Biediger, V. Gupta, D. Ertas, W.C. Elks, F.E. Dupriest, ExxonMobil.

A modeling tool has been developed that enables drilling engineers to design vibration-resistant bottomhole assemblies (BHAs), given tool placement constraints and desired directional objectives. The model predictions have been validated by direct comparison with field data in large, intermediate, and small hole sizes. This model is capable of handling different bits and tools, including bi-center bits, roller reamers, hole openers and eccentric mass stabilizers. When compared side by side, the model predictions and field observations compare well and have led to improved drilling results, including increased on-bottom drilling time, longer tool life, higher ROP, reduced nonproductive time associated with tripping, and even better hole quality.

As use of the operator's ROP management process spread through the company, drilling rates have increased and drilling vibrations have been identified as one of the most significant factors limiting further ROP and footage improvements. The capability to design BHAs to be less prone to vibrations is an important element in this process. This effort includes the use of real-time data from downhole sensors and Mechanical Specific Energy (MSE) diagnostics to fine-tune the actual drilling parameters from the predicted operating sweet spots.

Vibrations mitigation is posed more as a design problem than an analytical one. The model characterizes the lateral vibration, or whirl, tendencies of BHAs, enabling quick and easy comparison of potential BHA design candidates. BHAs can be designed to minimize vibration tendencies for a given set of operating parameters, or the model can be used to characterize the optimal set of operating parameters for a given BHA configuration. The model has unique displays to support both pre-drill vibrations forecasting and post-drill hindcasting. Several case studies will be provided to illustrate the value of this technology.

IADC/SPE 112733

New-Generation PDC Bits Allow Drilling at Record Rates of Penetration and Increased Durability in Challenging Algerian Applications. E. Aliko, T. Hunt, M. George, J. Nicol, Hughes Christensen.

Extensive research and development by the manufacturer has produced a new generation of PDC bits designed to drill harder and more abrasive formations than standard PDC bits, including those with the latest abrasive-resistant cutters. The new-generation PDC bits allow drilling of formations that once were only drillable with TCI roller cone bits and impregnated diamond bits. The success demonstrated in Algerian applications is likely to spread throughout the world, raising the performance bar and expectations for PDC bits.

The first new generation PDC bits were introduced in a 12 ¼-in. Jurassic Cretaceous application in the Algerian Sahara desert and immediately set performance records in one of the area's difficult fields. This application is characterized by a 2,000-m long vertical section usually drilled with packed rotary BHAs through a variety of formations ranging from soft and abrasive to very hard. The challenge in this area for PDC bits is drilling the whole section in one run and maximizing the rate of penetration. This challenge is made more difficult by a series of interbedded hard/soft formations that generate extensive vibrations. There also are extensive abrasive layers, leading to premature cutter wear and loss of aggressiveness and rate of penetration.

The authors will describe the technologies that were developed and included in these new PDC bits, as

well as the field results in a specific application in the Algerian Sahara desert.

Technical Session: Completions I - Operations

IADC/SPE 112661

Present and Future Well Intervention on Subsea Wells. S.N. Jossang, R. Friedberg, P. Buset, B. Gramstad, Island Offshore Subsea

Worldwide, there are more than 3,000 subsea wells, and the number is growing. To increase recovery from these wells, there is a demand for an efficient subsea light well intervention service, including repair, scale removal, installation and manipulation of mechanical devices (valves, plugs, screens, etc.), perforations and re-perforations, zone isolation, fluid sampling, PLT, chemical treatment, well abandonment, etc. Traditionally, this type of work has been done by drilling rigs. Light well intervention technology makes this type of service possible from a monohull vessel. The technology reduces the intervention cost to $\frac{1}{3}$, enabling more intervention work and resulting in better exploitation of subsea wells. The long-term objective is to increase recovery on subsea wells from an average 45% to 55%.

An alliance of a vessel owner, a wireline operator and a well control company offers a complete RLWI service. The alliance has performed RLWI services on the Norwegian sector since spring 2006 and made interventions on more than 20 wells, after succeeding to land a long-term contract. Continuous operations have resulted in ongoing improvement of systems and operation and provided important contributions to design and construction of new RLWI vessels and systems.

This paper will discuss the RLWI service in general, present challenges met, experiences made, and lessons learned during the 2006 and 2007 campaigns.

IADC/SPE 112648

Surface BOP Operations From a Multi-Service Vessel. C. Johnston, Helix Energy Solutions.

The Q4000 multi-service vessel is converted to accommodate a surface BOP, high-pressure riser and subsea shut-off device to enable drilling and completion operations to be conducted in the Gulf of Mexico. The system incorporates 13 $\frac{3}{8}$ -in. sized pressure control equipment, coupled with a 16-in. high-pressure riser system to enable slimbore completion of a previously drilled well in 2,400 ft of water in the Gulf of Mexico. Significant equipment modifications are required to enable operations in the form of drilling and completion fluid handling, treatment and circulation, as well as riser tension system and pressure control equipment control and development, all of which are discussed in terms of incorporation into the existing vessel infrastructure.

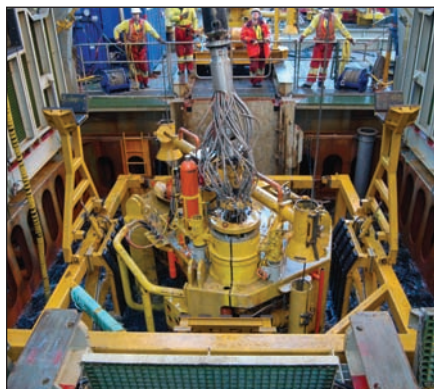
The application is to enhance a reduced-sized multi-service vessel for operations enabling completion of existing subsea wells in deepwater areas as a means to improve the economics for development of marginal fields. Longer term drilling as well as completion operations using the SBOP system will reduce overall development costs and further enhance marginal field development capability.

The current vessel design and the implications for upgrade to SBOP operations highlight the challenges faced with a multi-service vessel. Key issues are the requirement to preserve the multi-service capability as much as possible, pressure control equipment and high-pressure riser configuration within the existing vessel operating envelope coupled with riser tension capability installation.

This development is new within the Gulf of Mexico. It



IADC/SPE 112733: A new-generation PDC bit allows drilling of formations that once were only drillable with TCI roller cone bits and impregnated diamond bits.



IADC/SPE 112661: As the number of subsea wells increase, so does the demand for efficient subsea light well intervention service, which can be performed from a monohull vessel using light well intervention technology.

offers the potential for new completion and drilling options within the Gulf of Mexico from reduced size vessels and with a view to emphasising the potential for single well tiebacks where existing infrastructure is at a minimum.

IADC/SPE 112638

The Use of Multilateral Well Designs for Improved Recovery in Heavy Oil Reservoirs. S.R. Fipke, Halliburton; A. Celli, Petrozuata.

There are a variety of ways to achieve higher recovery factors from heavy oil reservoirs, but most of them involve the injection of thermal energy or chemicals to reduce the oil viscosity. While these techniques have been highly successful, they can also be very expensive when the steam generation and/or chemical injection costs are accumulated throughout the productive life of the field. A lower-

cost solution, one that has been very successful in the Faja Del Orinoco of Eastern Venezuela, is to use multi-branched wells (multilaterals) to increase reservoir exposure and achieve an arguably higher recovery factor. These multilateral wells have been shown to produce more oil over a longer period of time than conventional horizontal wells without any additional operating costs.

This paper will discuss the concept of using multilateral wells as an alternative to conventional enhanced oil recovery (EOR) techniques in heavy oil reservoirs. It will argue that the oil recovery factor of a reservoir that is drilled with increased wellbore exposure can be comparable to thermal/chemical EOR under the right circumstances, and that the project will have a much lower operating cost. While steam injection has become the successful mainstay of most EOR projects, there are many drawbacks, such as the costs of the steam generation and the emission of greenhouse gases. Multilateral wells can potentially offer an option to produce the same reservoir with lower costs while still recovering an increased percentage of the oil from the reservoir.

IADC/SPE 112774

Cementless Multi-Zone Horizontal Completion Yields Three-Fold Increase. B.D. Maddox, M. Wharton, ECA Holdings; R.L. Hinkie, B.P. Balcer, M. Farabee, Halliburton; J.W. Ely, Ely & Associates.

The method of using open-hole stimulation to increase a well's production is well known. However, the application of expandable swell packers and a hydrajet perforating stimulation technique in a 350°F open-hole horizontal well 15,700 ft TVD stretches the limits of modern technology. Recently, modern technology triumphed when the first Wilcox Meek 2 well in the Brazos Bell Prospect Area was drilled and completed to test the effectiveness of horizontal well technology in tight sand formations. This paper will cover the cementless completion process and explore the effectiveness of horizontal well technology in tight sands by comparing initial horizontal well production rates to offset vertical well production rates.

IADC/SPE 112701

Cement Slurry Performance and Set Cement Properties vs. Microsilica Densification. F. Daou, B.M. Piot, Schlumberger.

Microsilica is the extremely fine noncrystalline silica obtained in electric furnaces as a byproduct in the manufacture of elemental silicon and ferrosilicon alloys. This waste material, also improperly called silica fume, is available in different grades of various handling characteristics. It has been used for years as cement mixture in the oilfield and in construction and civil engineering industries. Its different applications derive from improving the slurry stability and the mechanical properties of the hardened material due to its extremely fine nature and high reactivity as a pozzolanic material.

This paper reviews typical uses of microsilica in oilfield cements. Particular attention is given to the influence of material grade, in terms of degree of densification, on slurry behavior and set cement properties. The physical properties of microsilica tested include specific gravity, loose and compacted bulk densities, and particle size distribution before and after being submitted to an ultrasonic treatment. Slurry behavior is evaluated in terms of rheology and stability.

The observation of set microsilica cement microstructure with a scanning electron microscopy coupled with an energy dispersive spectrometer clarifies the question concerning the dispersability of densified microsilica in cement slurry. An unambiguous correlation between physical properties of microsilica, slurry performance, and set cement

morphology is then established, leading the way to correctly specifying the quality of microsilica to be used in oilfield applications.

This work demonstrates that, contrary to common belief, not all grades of microsilica are equal, and that densified microsilica does not redispersed into small particles when mixed in a cement slurry. Therefore densified grades, which are popular for their ease of handling, do not provide the performances required for adequate zonal isolation that are normally expected from microsilica slurry.

Technical Session: Fluid Technology I

IADC/SPE 112629

Investigation of Factors for Strengthening a Wellbore by Propping Fractures. M. Wang, M.Y. Soliman, Halliburton; B.F. Towler, University of Wyoming.

Wellbore strengthening or stress cage has been recognized as an effective solution to lost circulation. One of the mechanisms found for strengthening a wellbore is propping fractures with particulate LCM that can increase hoop stress at the near wellbore region. However, without a good understanding of this mechanism, a potentially flawed design and implementation process can affect the job success in the field. One of the main issues is fracture stability under the strengthening conditions. This paper will describe those important factors for designing wellbore strengthening jobs under the necessary conditions including fracture stability through rock mechanics analysis.

IADC/SPE 112528

An Innovative Fluid Pressure Transmission Pill Successfully Used During Managed Pressure Drilling Operations in an HPHT Environment. E. Ronaes, O. Prebensen, R. Mikalsen, M I Swaco; K. Taugbol, S. Syltøy, S. Torvund, StatoilHydro.

In order to successfully perform MPD operation in a HTHP field offshore Norway, an innovative fluid technology was developed for well control. The drilling fluid used in MPD mode had insufficient density for tripping operations. To balance the reservoir pressure when tripping, an isolation pill was spotted in the upper part, leaving dense fluid on top of the well, making the total hydrostatic pressure in the fluid column sufficient for well control.

This development pill enabled pressure to be transmitted to the bottom of a well by placing the pill in between a dense fluid on top of a less dense fluid. The design and properties of this pill made it possible to run test wireline logs and eventually a test liner run through the pill, and at the same time maintain a pre-determined hydrostatic pressure on the well. In addition, the pill did not cause instability by interfacing different density fluids, as this would have a dramatic impact of the hydrostatic pressure. One of the criteria was to displace the pill out of the well by using the circulating system only. As this paper describes, the pill stayed intact during the entire operation, and displacement of the pill from the wellbore was performed successfully.

IADC/SPE 112645

A Novel Heat-Activated RSF to Treat Severe Cases of Lost Circulation: Case Histories From Mexico. G. Tirado, C. Pliego, A. Rendon, Pemex; I. Fowler, J. Marin, H. Ramirez, E. Soriano, Halliburton.

Lost circulation during drilling operations is a costly event that has plagued the oil and gas industry from its earliest beginnings. Drilling fluids are lost to the formation when the well is drilled overbalance through high permeability, fractured or easily fractured formations. In many cases, total lost circulation is experienced, where all drilling fluids are lost to the formation with zero returns to surface. This presents problems in trying to adequately cement casing strings and liners in place.

A range of commonly used conventional lost circulation materials (LCMs) are available to combat lost circulation. These can be very effective in cases of low permeability or small, fractured formations and are relatively simple to place in the loss zone. However, in cases of severe or total lost circulation, the use of these conventional LCMs can be ineffective, and attempts are made to stop the losses with the placement of dedicated lost-circulation treatments. These

dedicated treatments include specialty cements, gel plugs or even ordinary cement. This paper discusses the field application in a number of wells in the Burgos Basin in Mexico, of a novel temperature-activated rigid setting fluid composition that has been developed specifically to tackle the most severe cases of lost circulation.

IADC/SPE 112656

Method to Eliminate Lost Returns and Build Integrity Continuously with High-Filtration-Rate Fluid. F.E. Dupriest, M.V. Smith, S.C. Zeilinger, N. Shoykhet, ExxonMobil.

This paper describes a fluid system developed to build integrity continuously to prevent lost returns. Two key attributes of the fluid that enable this are engineered particle sizes and extremely high mobility of the carrier fluid through the solids, as reflected in API filtration tests. It is referred to here as a drill and stress fluid (DSF). In field application, circulating pressures that exceed integrity by 1.0-3.0 ppg have been sustained without detectable losses in depleted formations with permeability ranging from 1 - 1000 md and pay zones of 50 - 700 ft in length.

Lost returns treatments may be categorized as discrete or continuous. Discrete treatments are defined as those in which operations are stopped and the loss is treated prior to drilling ahead. The operator's practices for discrete treatments have been described previously. Continuous alternatives have been needed when the integrity is expected to be so low that losses would immediately result in underground flow or wellbore collapse. The continuous treatment methods developed in recent years have been low fluid loss systems that required filtrate flow to the fracture tip be controlled to relatively low levels. The operator's success with a system having uncontrolled fluid loss suggests tip growth may be manageable even with very high mobility of the carrier fluid through the solids.

This paper provides discussion of multiple factors that are believed to control tip growth in a high fluid loss system and implications for design of a drill and stress fluid. The results of the application of DSF are presented for six wells, including post treatment evaluation logs of the drilling induced fractures created while building stress.

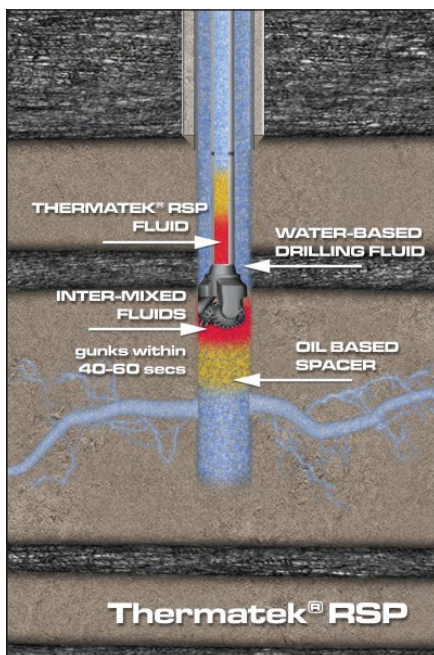
IADC/SPE 112595

Particulate Based Loss-Prevention Material — the Secrets of Fracture Sealing Revealed! N.M. Kageson Loe, M.W. Sanders, F. Growcock, M I Swaco; K. Taugbol, P. Horsrud, A.V. Singelstad, T. Omland, StatoilHydro.

Depleted reservoir drilling and drilling in deepwater environments are universally recognized as being technically challenging as a result of the narrow drilling margin that exists between the pore pressure and fracture pressure gradients. A

number of field techniques are available for mitigating many of the drilling problems encountered. Among these are specialised fluid engineering, including the use of chemical and particulate-based treatments for minimizing or preventing losses. In many instances, these techniques can be used to strengthen or stabilize the wellbore when drilling on or near the fracture gradient, thereby potentially eliminating the need for intermediate casing strings.

This paper discusses particulate-based treatment design with respect to fracture sealing. Substantial experience gained from innovative laboratory testing has highlighted the mechanisms and many factors that determine the effectiveness of the fracture seal. The particle size distribution relative to the fracture aperture, particle morphology, volumetric concentration, fluid rheology and fluid loss control influence whether the seal is established within the fracture or at the fracture mouth. Understanding this distinction is important with respect to selecting the optimum treatment and its application for given field conditions. Of all these factors, a number of critical parameters have been identified where these are discussed in context of laboratory and field experience.



IADC/SPE 112645: When conventional lost-circulation materials prove ineffective in cases of severe or total lost circulation, dedicated lost-circulation treatments may be applied.

Technical Session: Health, Safety and Environment

IADC/SPE 112736

Building a Well-Control Culture with WellCAP. S.M. Kropla, International Association of Drilling Contractors; O.A. Kelly, T. Gillis, P. Sonnemann,

Chevron; J.J. Metcalf, Newfield Exploration; O.L.A. Santos, Petrobras; R. Rodrigues, Transocean.

IADC's Well Control Accreditation Program (WellCAP) and WellCAP Plus provide drilling organizations with the building blocks needed to build a comprehensive well control culture at all levels. WellCAP's curriculum offerings have evolved steadily to keep abreast of industry needs. The system has been widely accepted by operators, contractors and service companies and has been adopted as the internal standard for companies such as Chevron, Occidental, Petrobras, PEMEX, Diamond Offshore, Transocean, and Nabors Drilling International.

The Introductory level of WellCAP is recommended for derrickmen and floorhands. The Fundamental level is recommended for driller and assistant driller. The Supervisory level is designed for the representative on the rig (company man), mud engineer, rig superintendent and toolpusher. Simulator exercises are required at the Fundamental and Supervisory Levels and is optional at the Introductory Level.

At the most advanced level, WellCAP Plus provides an alternative to the standard supervisory level for experienced rig and drilling management personnel. Participants experience a facilitated learning process that focuses on team problem-solving and decision-making skills. WellCAP Plus was developed with the assistance of the Texas Engineering Extension Service (TEEX) group of Texas A&M University.

IADC/SPE 112764

Using the Last Several Years of QHSE Data to Improve the Next Several Years of QHSE Performance. R.E. McClaine, Hercules Offshore; J. Stough, Syntex Management Systems.

Have you found the leading indicators for which continued execution truly does result in fewer injuries, less spills, and generally better QHSE performance? If so, can you prove it? If not, is it something you wish to do?

This session will dive into the topic of "leading indicators" and how combining a large global data set with some fundamental statistical methods can result in both finding those factors which truly affect performance outcomes and the mathematical support to prove it.

IADC/SPE 112341

Safe, Effective and Trouble-Free Rig Startups — Chance or Good Planning? D. Cormack, R. Richardson, T. Steel, R. Watkiss, KCA DEUTAG.

Successfully starting up rig operations is key to the ongoing success of a drilling project for both operator and contractor. Getting the HR, HSEQ & training elements correct at the outset can be the result of chance and good fortune or the result of integrated cross functional planning amongst a number of key stakeholders. One drilling contractor gained experience starting several major projects across the world in recent years. As part of the strategic growth plans for the organisation, it was going to experience in excess of 20 very diverse rig start-up operations over a 12-month period. Successful growth of this size, speed and variety could not be left to chance but had to be a result of good planning.

This paper will discuss how that organisation took the lessons it learned in the past and applied them in a structured manner via its corporate HSE plan.

IADC/SPE 112566

Accelerated Training and Competency Program. P. Tinchon, Pride International

One of the major challenges we face today is recruiting and retaining the workforce necessary to support the growth the entire oil and gas industry is experiencing. Compounding this challenge is the enhanced training and development required for new and less experienced employees in light of the retiring generation, the increase of drilling activity and the arrival of more than 100 new offshore units.

Pride International will address these challenges by accelerating the development of green hands and high-potential employees, as well as maintaining and improving the level of personnel qualifications. Pride has moved forward from a Training Management System to a Competency Management System. This system deals with each skill onboard, including safety, drilling, mechanics, subsea, electricity, marine. Each group is cycled through three groups of competencies: QHSE, operations and personal values.

Intensive training programs have been implemented that include not only theoretical and practical training but also leadership attitudes, safety team spirit, team building, loyalty, etc. In order to benchmark and assess the competencies of the personnel, a Quality Control System has been implemented. It tracks qualified personnel for various assignments as well as specific competencies demonstrated by the individuals. The paper will outline the Competency Management System and will include how the accelerated drilling program for new hires and National employees is implemented, what the goals are and the time for employ-



IADC/SPE 112396: Applying safety procedures and maintenance routines together can result in safer equipment, fewer lost working hours and a decrease in manhours in hazardous jobs.

ees to achieve the goals, the mechanism to benchmark, and ensure the QAQC of the Competency Management System.

IADC/SPE 112496

H.S.E. Culture — One From Many. D.A. Crochet, R.E. McClaine, Hercules Offshore; K.S. Callen, Performance Coaching International.

In three years, Hercules Offshore went from a privately held company with five jackup drilling rigs and 22 liftboats to a publicly held corporation with 73 drilling rigs, 64 liftboats and a workboat fleet. This rapid growth has left the challenge of growing one HSE or safety culture from 10 different parts. We intend to share the methodologies being used to grow one safety culture from many.

Often safety professionals attempt to grow a safety culture by adding to what is already in place, complicating the basic tools. Our observation has been that not only have some of our tools turned into paper exercises, but many do not even get that they might be something more. We are working under the assumption that basic safety tools like Job Safety Analysis, Permits to Work, Time Out and Hero (our behavioral observation tool) are not obvious. They are the building blocks of a safety management system requiring understanding. Through immersion training involving everyone, we are getting back to purpose by simplifying and streamlining, and creating belief and accountability.

IADC/SPE 112368

Tar Sands Drilling Waste Management — A Clean Solution. C. Nilsen, K.L. McCosh, M. Kapila, M I Swaco.

Tar sands are a combination of sand, clay, water and bitumen. In situ techniques using steam and/or solvents are used to reduce the bitumen viscosity such that it can be recovered and refined into petroleum products. Steam-assisted gravity drainage is an increasingly common technique that involves drilling two horizontal wells into the tar sand deposits. Steam and hot water is injected into the upper well to reduce the viscosity of the bitumen, which will drain into the lower well, where it can be pumped to the surface. The waste generated from drilling these wells is extracted from the drilling fluid by shakers and include sand contaminated with bitumen and drilling fluid. Treatment of this waste stream is challenging, and typically these sands are stored at the rig site or transported for disposal at centralized sites.

Novel technology for treatment of the tar sands drilling waste provides a simple and efficient process to produce clean sand that can be disposed safely in situ. The process also recovers tar that can be used as feedstock for further processing and refining. The continuous process is based on hot water addition, mixing and separation techniques to reduce the viscosity and specific gravity of the heavy oil to separate it from the sand. The energy used to heat the circulating water is recycled to minimize waste and maximize energy efficiency. Data will be presented to show the effective removal of tar from the sands to meet the current disposal limits of 0.1% oil by weight.

IADC/SPE 111490

Case Study: Hot Work Control and Safe Work Practices at Oil and Gas Production Wells. J.A. Banks, US Chemical Safety Board.

The CSB is an independent federal agency charged with investigating industrial chemical accidents. CSB investigations look into all aspects of chemical accidents, including physical causes such as equipment failure as well as inadequacies in safety management systems, regulations, and industry standards.

Three contractors died and one contractor suffered serious injuries in a 2006 oilfield explosion and fire in Mississippi. The contractors were standing on top of a series of four oil production tanks. They were preparing to weld piping to the tanks when a welding tool likely ignited flammable vapors from the tanks.

Failure to recognize the hazards posed by use of welding tools in a flammable vapor environment likely contributed to the incident. Failure to manage those hazards with well-established, safe work practices could have also contributed to the incident. During initial interviews with CSB investigators, employees stated that maintenance workers regularly tested for flammability in oil tanks by lighting and inserting torches into open hatches on tanks prior to welding. The CSB investigation of this incident will discuss appropriate flammability testing equipment and procedures.

IADC/SPE 112396

Safety and Maintenance — Benefits of Applying Them Together. M.D. Lanza, San Antonio Internacional.

This paper shows the relationship between safety and maintenance and how applying them together has resulted in the improvement of the safety conditions of the equipment, a decrease in lost working hours, and a decrease in the quantity of manhours in hazardous jobs. In order to maintain this improvement, these results are recorded to redesign maintenance routines and safety procedures. Our goal is to break the paradigm that divides safety from maintenance systems and thus, we will reach our zero accidents and zero failures objective.

IADC/SPE 112535

Well-Integrity Issues Offshore Norway. B. Vignes, Petroleum Safety Authority; B.S. Aadnoy, University of Stavanger

Petroleum Safety Authority Norway (PSA) has performed a "pilot well integrity survey" based on supervisory audits and requested input from 7 operating companies and 12 pre-selected offshore facilities/ wells. The wells were a representative selection of producers and injectors with variation of age and development categories.

The pilot project indicates that 18% of the wells in the pilot well integrity survey have well integrity failure/issue or uncertainties and 7% of them are shut in because of well integrity issues. The selection of wells and the companies indicates that this is representative.

The paper presents the results and conclusions from the pilot survey. A number of technical well failures also will be presented.

Technical Session: Tubulars I

IADC/SPE 111511

Effects of Boundary Conditions and Friction on Static Buckling of Pipe in a Horizontal Well. G. Gao, Chevron; S. Miska, University of Tulsa.

To our best knowledge, all available papers on buckling in horizontal wells have assumed that the pipe is very long so that the end conditions do not influence the buckling force. Also, in all but one paper (Mitchell), an assumption is made that there is no friction between the pipe and wellbore. Therefore the main objective of this study is to remove this assumption and provide more realistic solutions (including friction) for practical design application.

A comprehensive buckling model, a group of fourth order non-linear ordinary differential equations, is derived with application of the principle of minimum potential energy. Then the equations were normalized to make the solutions independent of the wellbore size, type of pipe and mud. The critical sinusoidal buckling load of tubing was analyzed under different boundary conditions typical for drilling and well completion applications. The results show that the effects of boundary conditions can be neglected when the dimensionless length of tubing is greater than 6. The dimensionless length of pipe depends on the clearance between tubing and the wellbore, the bending stiffness of the tubing, unit weight, and is proportional to the length of the pipe. The authors also investigated the effects of friction on both sinusoidal and helical buckling for a long pipe with dimensionless length greater than 6. The results show that friction will significantly increase the critical loads for both sinusoidal and helical buckling, and reduce the amplitude of sinusoidal post buckling configurations.

IADC/SPE 112547

Development of Gas-Tight, Pressure-Rated, Third-Generation Rotary Shouldered Connection for 20,000-psi Internal and 10,000-psi External Pressure Service. J.N. Brock, M.J. Jellison, A. Muradov, Grant Prideco; B.J. Vinson, Sub Surface Tools.

This paper presents the results of a two-year comprehensive effort to design, test and qualify third-generation rotary shouldered connections (RSC) for a 20,000-psi internal and 15,000-psi external pressure service. ISO13679 testing

methodologies for casing and tubing were modified to evaluate the RSC pressure capability. Results from extensive finite element analysis and laboratory tests programs designed to produce harsh, aggressive dynamic loads to the connections are presented.

IADC/SPE 112624

Analysis of Control Lines Strapped to Tubing. R.F. Mitchell, Halliburton; S.T. Ellis, G. Siappas, A. Colyer, Chevron.

Hydraulic control lines are commonly used to actuate surface-controlled sub-surface safety valves, and new applications include choke operation and the control of more complex "smart well" completions. In general, control lines are not subject to routine failures. However, the analysis of worldwide completion failures indicates control lines to be the principal cause of failure. In fact, control lines and associated components such as clamps and fittings, are not engineered with the same rigor as the rest of the well completion.

The first step in understanding control line failure is predicting the loads and stresses in a control line strapped to the tubing. Tubing movement causes loads in the control line through stretching and bending. To a lesser degree, the tubing is loaded by the control lines. To determine this interaction, a calculation is performed where the control line and the tubing are treated as a composite, with axial displacement constrained to be the same in both. This analysis provides the average stress state in the control line. Because the control line is fixed at only certain points along the tubing, the variation in stress from the average must be determined between clamps. This paper provides the technical details for both calculations.

IADC/SPE 112678

What Really Happens to High-Strength Drillpipe When Taking a Sour-Gas Kick? H.F. Spoerker, W. Havlik, OMV Exploration/Production; M.J. Jellison, Grant Prideco.

Drill pipe material selection in sour applications is significantly more complex than for casing and tubing. If sour conditions exist, NACE MR0175 provides clear guidance for selecting casing and tubing materials. The situation is somewhat different for the drill string. Per NACE MR0175, all API drill pipe grades, including S 135, are acceptable if SSC is avoided by controlling the drilling environment. However, during a gas kick, the drilling environment cannot be controlled for a period of time, and direct exposure to H₂S gas can occur. Sour gas and high-strength steel are generally accepted to be incompatible. However, when drilling beyond 20,000 ft, S 135 and higher steel grades become necessary to support their own weight, and due to the elevated downhole pressures in the range of 15,000 to 20,000 ksi, even minimal concentrations of H₂S result in partial pressures that are considered hostile for these steel grades. The paper presents initial results from a joint industry project exposing S grade drill pipe samples to various H₂S concentrations in temperature ranges from 70-170°C and exposure times of 1-3 hours.

The paper also presents the first draft of a field guideline supporting engineers and well site personnel in their decision whether to pull a string after killing the well or continue drilling operations.

IADC/SPE 112105

Connection Fatigue Index (CFI): An Engineered Solution for Connection Selection and a Replacement for BSR. S.E. Ellis, T. Wadsworth, K. Lee, M. Gerdes, S. Altizer, T H Hill Associates

For decades, the industry has used Bending Strength Ratio (BSR) as a guideline for fatigue design considerations in drill collars and other stiff body BHA components. Generally, a connection with a BSR of 2.5 is considered to have a fatigue balance between the pin and box as governed by the connection's overall dimensions. The use of BSR as a design constraint is widely accepted, but it does not account for many of the factors that drive fatigue in rotary shouldered connections. This is illustrated by the fact that two dissimilar connections (type, size, or both) can have the same BSR but display dramatically different fatigue performance.

Connection Fatigue Index (CFI) is a new design approach that takes into account the dimensional, material, and usage parameters that directly impact the fatigue performance of the connection. By accounting for fatigue drivers, such as unique features of the connection type (i.e., thread root radius, thread taper, lead, pitch diameter), material properties, stress relief features, applied makeup torque, and loading condition, CFI more accurately represents the relative fatigue performance of rotary shouldered connections. This paper describes advantages CFI presents over BSR, basic methodology used to determine CFI, and how and when to use CFI.

IADC/SPE 112740

Evolution of Drilling Programs and Complex Well Profiles Drive Development of Fourth-Generation Hardband Technology. A. Chan, D.

Hannahs, M.J. Jellison, Grant Prideco; M. Breitsameter, D. Branagan, The NanoSteel Company; H. Stone, Noble Drilling Corporation; G. Jeffers, Nabors Drilling USA.

The evolution of drilling programs and complex well profiles has driven the industry to develop new, more suitable hardband materials. This paper reviews the historical changes in drilling practices, development of drill stem hardbanding materials, and their shortfalls in meeting the industry's needs. Testing, verification, and performance evaluation of hardband materials have followed a similar evolution. Also presented are recent developments in laboratory testing to repeatedly predict hardband/tool joint wear performance. Finally, the development, laboratory testing and field trial of a fourth-generation hardband material is described.

IADC/SPE 112587

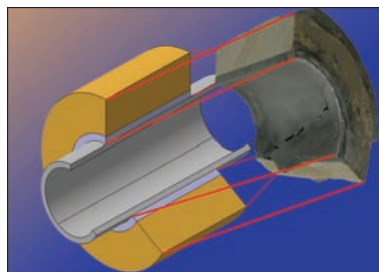
Latest Developments and New Technology for Coiled-Tubing Sidetracking Applications. G.L. Garfield, G. Mackenzie, Baker Oil Tools.

The influence of improved technologies and the latest operational developments has led to a significant impact in the arena of coiled tubing drilling operations. These influences are also making themselves known in the underbalanced coiled tubing drilling sector. Sidetracking operations have traditionally utilized a philosophy dominated by threaded tubular drilling conveyance methods; however, with the growth of coiled tubing drilling applications in recent years, coiled tubing deployed bottomhole assemblies for sidetracking a well are beginning to gain acceptance as a standard practice. A major advantage of a coiled tubing deployed exit system is the ability to mill a window in the casing in a restricted wellbore environment. The whipstock can be deployed in a live well condition without the necessity of removing the completion equipment, thus eliminating the requirement for a workover rig and negating the need for kill weight fluids. The systems can be deployed on either electric wireline or coiled tubing, making them ideally suited for restricted bore access and allowing the window to be milled below the completion. The discussion will include a comprehensive overview of utilizing a new whipstock system with the conveyance method of coiled tubing and electric wireline in order to create a casing window. The overview will also communicate general practices and tool selection criteria with the case histories representative of the placement of the whipstock with coiled tubing and the window milling being performed with coiled tubing workover motors.

IADC/SPE 111243

Analysis of Casing-Shift Problems in Compacting Reservoirs. Y. Jinnai, N. Morita, Waseda University.

In the past, casing shift problems were suspected of causing production decline. It motivated field engineers to investigate whether casing shift occurred or not



IADC/SPE 111243: Lab tests were conducted to investigate how the bondings of casings and formation breaks under confining stresses.

by shooting radioactive bullets in productive layers and measured the relative movement of casing and formation. However, the results were ambiguous due to the uncertainty of wireline logging depth measurement during a long reservoir compaction period. In this paper, it is investigated, how the bonding of casings and formation breaks under confining stresses; how a casing slides after the bonding breaks; the magnitude of shear force to induce casing shift.

To achieve the above objectives, the following laboratory measurements were performed:

(1) Construct test samples simulating casings bonded with formation with cement and mud cake; (2) Conduct experiments of measuring shear force to induce casing shift under confining stress; (3) Simulate the correlation of depth and shear and normal stresses around a cased hole with a finite element model for compacting reservoirs; (4) Compare the results of experiments with the simulations to judge the magnitude of casing shift.

The experiments showed that a casing just does not slip when a shear load is applied. It accompanies shear failure of cementing materials between formation and casing. Calculations are performed to estimate the shear stress induced at casing and cement and cement and rock interfaces during reservoir compaction using a finite element simulation model. Comparing the laboratory measured sliding shear stress with the calculated shear stress, it is concluded that a small casing slippage may occur at casing and cement and cement and rock interfaces. The small slippage may be serious enough to cause production reduction. Hence, re-perforation at the expected shift intervals would recover the productivity.



IADC/SPE 112312: A new drawwork using permanent magnet motor technology is ideal for use on newbuilds or upgrades.

Technical Session: Rig Equipment

IADC/SPE 112312

New Large-Capacity Compact Drawworks for New Builds and Upgrade Jobs. H. Kverneland, M.M. Moe, A. Austefjord, A. Kyllingstad, National Oilwell Varco.

A new drawwork using permanent magnet motor (PM motor) technology has been developed to make a small and compact drawwork for use on newbuilds and upgrade jobs. This technology using an inside-out PM motor integrated in the winch drum was first introduced to the offshore market two years ago in a manrider winch application. It is now adapted to larger horsepower winches, such as crane winches and drawworks. This paper will focus on the drawwork application, improving safety and reducing size and weight of the drawwork substantially compared with standard drawworks with equivalent hoisting capacity.

The drawwork is designed for a maximum hook load capacity of 1,100 tons and maximum tripping speed of 5,22 ft/sec, and the size and weight reduction compared with a traditional drawwork is more than 40%. The mechanical design of the drawwork is simple, with fewer components than normal. When the PM motor is short-circuited via resistors, the PM motor will start working as a generator, meaning that the PM motor works as a dynamic brake. This feature is used in case of emergency lowering, safely lowering the load with the dynamic brake without jerking the load down with the mechanical disc brakes.

This paper will focus on challenges during manufacturing and testing of the drawwork and its control system, and the test results related to this.

IADC/SPE 112869

Dual Activities Without the Second Derrick — A Success Story. T. Webb, K. Selamat, Murphy Sabah Oil Company; B. Fletcher, Seadrill.

Kikeh Field is located 120 km from Labuan in offshore Sabah Malaysia. The field, in 1,328 m water depth, is the first deepwater development in Malaysia and consists of subsea and SPAR dry wells. The West Setia is a tender assist drilling rig used for SPAR development activities. This rig uses pontoon and column tanks to keep it floating in the water like a semisubmersible. However the derrick and partial rig package still sits on the SPAR or platform deck to carry out drilling and completion operations.

The scope of completion operations covers not only standard scope of installation, i.e., lower, middle and upper completion, but also includes displacing fluid with nitrogen for riser dewatering and well clean-up and testing. Several logging operations were also identified as tasks to be delivered during completion operations.

Due to the wide scope of completion work, detailed work assessment was conducted to review the possibility of making sure some part of completion scope could be done off the rig's critical path operation in a safe manner. Resulting from the assessment, at least seven completion related activities were identified. This paper will detail each of the operations involved, rig capabilities and limits, explains the challenges, safety considerations and lessons learned, time saving and value created from each of the activities.

IADC/SPE 112584

Full Field Development of a Remote Oilfield in East Siberia With 4 Rig

Simultaneously Delivers Field Record in Drilling. M.L. Drnee, Schlumberger.

This paper presents the start-up of a full field development of a remote oilfield in East Siberia in 2007. Four rigs were drilling simultaneously on four pads, delivering a field record in drilling. The Russian client drilled three vertical wells before 2007. The first and slowest directional well using an "old" Russian rig was still drilled significantly faster compared with the three old wells. Two wells using a "modern" Western rig were the fastest wells drilled.

Zero failures of motors or gyros occurred despite an inability to service equipment during the first half of 2007. Western directional drilling and MWD crews operate on all rigs run by three different drilling contractors (one Russian, two Western). Synchronization with the crews results in reduction of BHA handling times on all four pads. Teamwork in general has been outstanding, especially with regard to difficult logistics due to the remoteness of the field. The challenge was that DD/MWD tools all had to be delivered on time before closing of the winter road.

Innovation has been the key to the success of this first multi-segment project in Russia. No maintenance of MWD tools was possible in the field until a base was complete using an inflatable tent (First in Russia). An in field shop for MWD electronics and modulators was up and running by mid 2007. Advanced satellite communication has been setup for operations in each pad, and the base using real-time data channels to facilitate support from a Sakhalin based operations support center.

IADC/SPE 112637

Novel Automation Interface Improves Drilling Efficiency and Reliability. F. Florence, M. Guggari, W.L. Koederitz, H. Rodriguez, National Oilwell Varco; C. O'Kelly, D. Russell, Schlumberger.

Automation of drilling operations to date requires substantial capital investment and major construction or renovation to implement the technology. A new method has been developed using a small electronic controller coupled to the existing controls of conventional rigs, land and offshore. This simple and reliable controller is a conduit for service companies/operators to apply the latest algorithms to drilling operations employing mechanical or electrical rigs of many different designs. This will inevitably lead to experts directly controlling drilling operations, which will mitigate the shortage of experienced personnel.

The system is commercially available as a mud pump controller used on a variety of land installations and on a deepwater drillship in the Gulf of Mexico. Complex command sequences are easily implemented from pulldown menus. Downlinking to rotary steerable tools continues with no misruns and often at depths, speeds and differential pressures/flow rates unattainable when done manually. It was also successfully field tested with rotary tables and drawworks brakes. This paper examines laboratory data, field tests and results from initial commercial applications to quantify risk reduction available from the new system.

IADC/SPE 111757

Development and Testing of a Rig-Based Quick Event Detection System to Mitigate Drilling Risks. W.D. Aldred, R. Hutin, J.C. Luppens, G.M. Ritchie, Schlumberger.

High accuracy, speed and a low false alarm rate are critical to the success of event detection systems and the reduction of NPT due to unplanned events. The balance between them has been difficult to achieve; however, the application of a probabilistic approach with the use of Bayesian methods has shown significant promise. The results of a research prototype for kick detection using such methods were described in a previous paper. The increase in processor speed and memory capacity of computers has meant that these new approaches to large-scale data analysis in real time are now more widely possible. This paper describes the extension of this work to develop a rig-based quick event detection (QED) system for mitigating a number of common drilling risks, including kicks, circulation loss and drillstring washout detection.

IADC/SPE 112743

Reducing Equipment Integration Cost and Risk in New Rig Construction. D. Reid, J. Hoefflich, J. Ogg, National Oilwell Varco.

The paper presents methods used in the development and execution of new rig construction projects that involve structures with multiple machines for drilling and pipe handling, as well as the power and control systems to drive them. Advanced uses of modeling and simulation allow accurate 3D models to be test driven using the actual control software that will be used on the rig, well in advance of construction and commissioning. Rig floor layouts, machine specifications and placement can be checked and verified in the models, with opportunity to change and optimize prior to fabrication and assembly. Further, the rig system with final structure, equipment models, rig processes and control software can be tested and pre-commissioned prior to final commissioning, reducing the time required to debug physical interfaces, processes and software in the shipyard.

IADC/SPE 112565

Automated Real-Time Hookload and Torque

Monitoring. R.J. Kucs, H.F. Spoerker, OMV Exploration/Production; G. Thonhauser, University of Leoben; P. Zoellner, TDE.

Today, important parameters to enable a reduction of lost and hidden lost time during drilling, like hook loads for pulling and slacking off the drill string and torque for drill string rotation, are still taken manually. Analysing torque trends during drilling and reaming is hardly done. A key to reduce lost and hidden lost time by analysing drilling data is to automatically recognize ongoing operations in real time from this data. That allows to automatically identify and pick pulling up and slacking off, as well as rotating hook loads, and torque values without spending extra time or work force. Relevant parameters can be sampled and analysed automatically in real time from the rig sensor data stream without interfering drilling operations. This automated process allows monitoring changing torque and drag trends for each stand of drill string moved during drilling, tripping or reaming operations.

To monitor trends in the torque and drag development in real time, parameters may be combined with simulated hookload and torque curves in a graphical way. Simulated values are imported from engineering applications. This allows the user to react immediately, not only after hand taken values are manually entered into a graph. The possibility to broadcast all the data to computers worldwide enables a great level of cooperation. Instant measures against increasing torque and drag can be taken before reaching critical ranges on a stand per stand basis. Also, excessive reaming and washing can be avoided as low torque and drag may be an indication for a good hole quality. This can save wellbore treatment time.

The paper presents the development of the system, its validation against live well data from recent 20,000-ft wells in the Vienna basin and the planned application of the system on an extended-reach field development project offshore New Zealand.

IADC/SPE 112564

An Equation Between a Second-Generation

Semi and Drilling Extended-Reach Well in Tunisia. D.C. Dupuis, Pride Forasol; S. Hancock, BG International.

To develop its Miskar field offshore Tunisia, British Gas made a call for tenders in 2005 during tight market conditions prevailing at the time. After reviewing MODU characteristics, a second-generation semi from Pride International, the Sea Explorer, was selected. This unit was designed in late '70s and did not have all necessary features and capacities to drill a high-temperature, extended-reach well. Range was TMD 6,740 m (22,200 ft) TVD 3,400 m (11,150 ft). Minor modifications were made to the unit. The paper will highlight the drilling constraints and hazards of such a well, not limited to the well architecture but also the geology. A brief well history will be given, plus the drilling campaign results and lessons learnt. This paper concludes on the upgrade possibility and capacity for a second-generation semi to match the challenges of today's high-profile wells.

Technical Session: Deepwater I

IADC/SPE 112872

Trapped Annular Pressure Mitigation: A

Spacer Fluid That Shrinks (Update). J.B. Bloys, M.E. Gonzalez, J. Lofton, R. Carpenter, S. Azar,

D. Williams, J. McKenzie, J. Capo, Chevron; R. Hermes, Los Alamos National Lab; R. Bland, R. Foley, F. Harvey, Baker Hughes; J. Daniel, F. Billings, I. Robinson, Lucite International; M. Allison, Flow Process Technologies.

In deepwater subsea completed wells, spacers or drilling fluid are commonly trapped in casing annuli between the top of cement and the wellhead. When these trapped fluids are heated by the passage of warm produced oil and gas, thermal expansion can create high pressures (10,000-12,000 psi or more), collapsing casing. Mitigation methods such as vacuum-insulated tubing, nitrogen foam spacers, crushable urethane foam insulation, etc. are somewhat successful but are either very expensive, logistically troublesome or have unacceptable failure rates.

A new approach has created a water-based spacer fluid used just ahead of the cement containing 20%-25% of emulsified methyl methacrylate monomer (MMA). Upon polymerization, the MMA phase shrinks by 19%, offsetting thermal expansion of the spacer avoiding catastrophic pressure. The temperature of the polymerization can be controlled by an appropriate type and concentration of initiator, and premature polymerization during spacer placement can be prevented by an appropriate type, and amount, of inhibitor.

IADC/SPE 112669

Challenges of Directional Drilling Through

Salt in Deepwater Gulf of Mexico. R.R. Israel, P. D'Ambrosio, A.D. Leavitt, Schlumberger; J.M. Shaughnessy, BP; J. Sanclemente, Chevron.

As an increasing number of 6,000-ft plus deepwater developments come on stream in the Gulf of Mexico (GOM), project economics dictate that fewer subsurface drill centers be used to develop these

fields. This requires longer step-out wells, pushing kick-off points higher up the wellbore, often occurring within extensive salt bodies. Salt drilling is still a relatively new practice and presents operators with many drilling challenges that are still not totally understood. Adding a directional component to drilling through salt not only magnifies the issues of traditional salt drilling but introduces new challenges that require different approaches to ensure successful delivery.

This paper will discuss the challenges faced and the lessons learned by two major deepwater GOM operators along with the directional service company in drilling directionally through the salt. Together, these companies have drilled over 100,000 ft of salt in the GOM. They have encountered and managed many of these challenges that extend past the traditional pre-drill and real-time directional issues, into the post drilling phase with issues such as casing and cement design for managing salt loading and ensuring long term wellbore viability. Several case studies will be presented, and critical areas for success will be identified.

IADC/SPE 111600

Deepwater Bitumen Drilling: What Happened Downhole? G. Han, K.C. Hunter, J.F. Ressler, J. Osmond, Hess Corporation.

Tar formations have posed significant challenges to deepwater Gulf of Mexico drilling operations. Many operators such as ConocoPhillips (Spa Prospect), Chevron (Big Foot) and BP (Mad Dog) have reported tar encounters and associated significant costs. Fundamental questions, however, remain unclear and controversial. For example, how tar behaves at in situ conditions, what shape is tar formation, what mechanisms drive tar into wellbore, etc.

This paper highlights a part of comprehensive efforts to drill through the tar encountered in a deepwater Gulf of Mexico field.

IADC/SPE 112732

Deepwater Exploration Well Pre-drill DST Sanding Potential Prediction Using Probabilistic and Deterministic Approaches. X. Yi, J. Sabolcik, H.E. Goodman, B.W. Walton, Chevron.

Sand control decisions are often made based on a deterministically predicted Safe 1 Drawdown Pressure (SDP) without proper regard to the amount of uncertainty associated with the value of SDP. These uncertainties can be large when planning a drill stem test (DST) for a deepwater exploration well. On the one hand, predicting too low of a SDP for a DST can result in unnecessary sand control. Predicting too high of a SDP can lead to sanding during the test, which can cause numerous problems and ultimately cost much more than sand control installation. Thus, a probabilistic study is warranted to quantify the expected sanding risk through a SDP probability profile, which can be used to estimate the risk of the expected value of a decision to install sand control or not.

In this study, data from 12 offset wells in nearby blocks were reviewed. First, a regional geomechanical model was calibrated and validated based on offset data. The model was used with a sanding prediction model and was calibrated and validated based on offset DST and sand control data. Next, a statistical analysis of regional in situ stress, sand pressure and rock properties for different sand intervals was performed to generate the necessary probability distribution functions (PDF) and used as inputs to a SDP Monte Carlo simulation. Finally, a deterministic approach was used to predict SDP. A comparison of SDP from the two approaches indicates that the mean results were consistent but that the resulting SDP PDF from the Monte Carlo simulation approach provides significantly more information.

IADC/SPE 112756

Solid Expandable Tubular System Mitigates High-Pressure Zones With Record Length. W.H. Bagley, D.E. Schultz, Nexen Petroleum USA J.S. Mueller, Marcus Vondenstein, H. Chowdhary, Enventure Global Technology.

In addition to the usual challenges encountered in deepwater projects, dealing with fluid loss can quickly compound an already difficult environment. With deepwater objectives becoming more commonplace in order to meet market demands, operators have had to utilize enabling technologies that are robust enough to address multiple problems. The recent application of a solid expandable system in a deepwater project was used to isolate depleted sands and stop extreme fluid losses without sacrificing hole size. Over 6,865 ft of 7 ⁵/₈ x 9 ⁵/₈ in. expandable openhole liner enabled the operator to drill

through depleted sands and reach the target objective with adequate hole size to complete the well with a 7-in. flush joint liner.

Technical Session: Completions II—Multilateral and Multilayer Completions

IADC/SPE 112115

Managing the Retrieval of Triple Zone Intelligent Completions in Extended-Reach Wells Offshore California. L.L. Izquierdo, T.U. Ceccarelli, Schlumberger; G.P. Hertfelder, K. Koerner, Plains Exploration and Production Company; S.V. Pace, Chevron.

An independent operator offshore California has successfully achieved triple zone intelligent well completions in an extended-reach drilling (ERD) campaign in its Rocky Point field. To date, two workover interventions have been performed in five deployments. The Rocky Point reservoir is a highly fractured carbonate and can rapidly initiate water production. During the production stage it was recognized that two of the wells did not achieve the required zonal isolation evident by increasing water cut. Thus, the operator made the decision to retrieve these completions to conduct liner cement repairs. These triple zone completions are controlled by 3-in. tubing retrievable flow control valves, open/close and multiple position, that work with dedicated gauges for pressure and temperature monitoring. Each productive zone was isolated by three multiple port retrievable production packers.

This paper describes the feasibility of deploying explosive jet cutters by pumping wireline conveyed assemblies to locator profiles above each packer, which allowed for simple, cost-effective intervention.

IADC/SPE 112116

Intelligent Well Completions System Integration Test Mitigates Risk. E.J. Coludrovich, S.V. Pace, S.D. Brady, Chevron; C.F. Campo, Halliburton

Completions in deepwater subsea applications are becoming increasingly more expensive and complex. This complexity is compounded by the challenges of installing intelligent completion equipment in deepwater environments. Reliable completions are a direct result of how well the pre-planning and procedures are implemented. The industry is challenged to integrate multiple service provider equipment and procedures into a single intelligent completion system. Intelligent Well Completion System Integrity Tests (IWC SIT) are being utilized as a proactive means to mitigate risk. This paper is an overview of an IWC SIT conducted in March 2007 for a West Africa deepwater field. The planning, implementation and learning captured from the operation will be presented.

IADC/SPE 112476

Multiple Layer Completions for Efficient Treatment of Multilayer Reservoirs. G.L. Rytlewski, Schlumberger

A new method of completing multiple layer formations has been successfully tested in the United States and Canada. This new method places sliding sleeve valves in the casing string and completes the well with normal cementing operations. The sliding sleeve valves are opened one at a time to fracture layers independently without perforating.

The valves of the new method have a design feature allowing a theoretically unlimited number of valves to be placed in a single well without incremental reductions to the ID, thus allowing normal cementing operations. A control line is connected between sequential valves. When the bottom valve opens, the control line becomes pressurized and transfers this pressure to a piston in the valve immediately above. This piston squeezes a C ring and makes the ID smaller. At the end of the fracture treatment to the lower valve, a dart is dropped during the flushing operation. This dart lands on the contracted C ring and seals the bore inside the sliding sleeve. Pressure is then increased until the next valve is pumped open. When this valve opens, the next control line is pressurized, squeezing the next C ring.

The main feasibility issue with this cemented sliding sleeve concept was frac-

ture initiation pressure through the cement and into the formation without perforated holes. Testing was conducted that predicted fracture initiation pressure to be similar to that encountered in perforated casing or even lower. Fracture initiation pressures were closely monitored during several field tests and confirmed that perforations were not needed to initiate fractures in the formations. This paper describes these new completions, how the valves work, and how the valves performed during the field test campaign.

IADC/SPE 112726

Application of Flow-Control Devices for Water Injection in the Erha Field. D. Haeblerle, A.S. Nwankwo, J. McDermott, B. Duffy, S.V. Gosavi, M. Grubert, ExxonMobil

The Erha field is a deepwater subsea oil development in OPL 209 offshore Nigeria. Due to the potential for reservoir compaction and early water breakthrough in the Erha North reservoir, pressure maintenance and injection conformance is considered critical to project economics and reserves capture.

This paper presents a case history of a successful field application of an innovative water injector completion technique addressing the issue of long-term injection conformance. Stand-alone screens with flow control devices (i.e., downhole chokes) and openhole packers were utilized on the two most challenging water injectors in the Erha field. The completion objectives were to: (a) target multiple intervals to reduce well count and cost; (b) sustain target injection rates and allocations; and (c) install sand control to prevent wellbore fill. Traditional water injector completion techniques, such as frac packs or openhole stand alone screens, did not meet all objectives.

Detailed completion simulations and fracture modeling were conducted to design the completions to their unique geologic settings. It is expected this completion technique will maintain the desired injection allocations to the four target intervals over the well life in the matrix and fracture pressure regimes. Upfront planning, communication and alignment between subsurface and drilling organizations enabled a successful real-time completion design and resulted in an operational success with less than 2% non productive time on the first injector.

IADC/SPE 111465

Capillary Tube Technology in Downhole Pressure Acquisition and its Application in Campos Basin Brazil. P.G. Cassara, Petrobras; J.C. Burgoa, E.A. Almanza, P.D. Ringgenberg, Halliburton

Petrobras considered cost effectiveness and reliability as the most important requirements for implementation of downhole pressure monitoring. The BG 16 Petrobras Well, located at Bagre Field, Campos Basin, was completed using capillary tube technology for downhole pressure acquisition. The system was considered as an accurate, dependable and cost-effective monitoring tool to work under dynamic and shut-in conditions.

The paper will discuss the use of this technology to collect reservoir information for pressure transient analysis during flowing and surface shut-in periods, showing the benefits of this application in long-term continuous reservoir monitoring.

Results obtained from the use of capillary tube technology compared with reservoir information collected by other memory gauges will be presented to allow evaluation of the performance of this system with other data acquisition technologies. The system has been successfully deployed on a number of wells worldwide and the paper will present case histories in this field in Brazil as illustrations of the capacity.

IADC/SPE 112755

Successful Field Appraisal Well Makes Single Diameter Wellbore a Reality. R. McKee, J.W. Fritsch, Enventure Global Technology

Developing revolutionary technology requires persistence, perseverance and vision to make an idea to a reliable product. A key factor in achieving the objective stems from how effectively the product development philosophy garners real results. For the development of the single-diameter wellbore, this philosophy resulted in a phased process that brought the technology from a concept to a reality.

This technology had to undergo final validation of some of the optimized components before entering the final phase of the development process. This phase consisted of qualifying the tool for a specific complex application, with all of the components having been previously qualified for functionality. Successful integrated testing on the single-diameter system will result in qualifying the phased expansion system. The actual field appraisal test (FAT) recently completed simulated the deployment operations by imaging hole angle, hole size, mud types, drill bits and any other environmental variables that factor into the complexity of the downhole conditions.

This paper will explain the product development philosophy and process used to drive the development of the single-diameter wellbore. It will detail the current status of the technology, the process to determine quantifiers and the actual FAT and results.



IADC/SPE 112872: In deepwater subsea completed wells, trapped spacers in casing annuli can create high pressures. A new approach has created a water-based spacer fluid containing emulsified methyl methacrylate monomer (MMA). Upon polymerization, the MMA phase shrinks by 19%, offsetting thermal expansion of the spacer, avoiding catastrophic pressure.

Technical Session: Drill Bits and Hole Openers

IADC/SPE 112670

Concurrent Rotary-Steerable Directional Drilling and Hole Enlargement Applied Successfully: Case Studies in North Sea, Mediterranean Sea and Nile Delta. S. Jones, J. Sugiyara, Pathfinder Energy Services

Underreaming with a rotary steerable system (RSS) is becoming more commonplace simply because significant cost savings can be obtained by eliminating the need for designated

hole-opening BHA runs. The risks associated with designated hole-opening runs, such as accidental sidetracks in soft unconsolidated formations, can also be reduced. However, RSS underreamer assemblies are often challenged with BHA instability, excessive vibration and stick slip problems when the two different cutting structures (a bit and underreamer) in the BHA interact with significantly different formations.

This paper describes case histories of directional wells that have been drilled with both point-the-bit and push-the-bit RSS underreamer assemblies in the North Sea, Mediterranean Sea and Nile Delta. In particular, RSS underreamer assemblies opening from 13 in. to as large as 17 1/2 in., using 12 1/4 in. pilot holes will be discussed.

IADC/SPE 112785

Multi-Diameter String Tools Deliver Lower Cost-per-Foot in Demanding Rotary Steerable Applications. S.P. Barton, W. Jones, R. Young, ReedHycalog; H. Rorvik, Halliburton.

The use of underreaming tools in conjunction with rotary steerable systems has increased dramatically in the recent years. Although excellent performance has been delivered with the mainstream commercial tools, alternate options have been developed to enable a rotary steerable tool to drill the pilot hole in conjunction with an underreamer to open the hole, in a single run. The most popular current option involves a weight- or hydraulic-activated underreamer. However, fixed blade multi-diameter reaming tools have recently been developed for use within rotary steerable assemblies:

1. An eccentric string reamer that will pass through a small pilot hole but then drill and produce a larger hole. This provides a significantly lower cost hole opening option.
2. A concentric string reamer that utilizes a tapered design incorporating a mid and main reamer section. This design uses a mid reamer that enlarges the pilot hole to an intermediate size and stabilizes the main reamer above it on its gauge pads. Because of its design, the mid reamer stabilizes the tool even if the pilot hole is of poor quality or is overgauge.

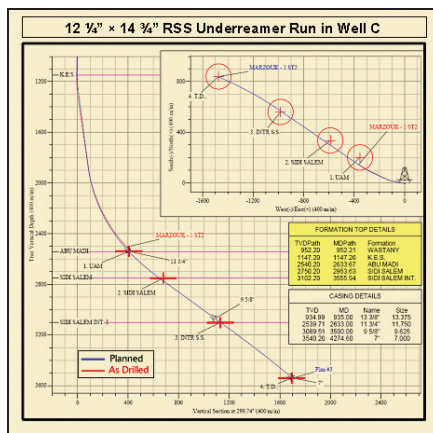
Several distinct applications are documented where these fixed bladed solutions, in combination with both push and point rotar steerable tools, have proven successful.

IADC/SPE 112647

A Systematic Approach to a Better Understanding of the Concentric-Hole-Opening. Process Utilizing Drilling Mechanics and Drilling Dynamics Measurements Recorded Above and Below the Reamer. I.J. Thomson, S.R. Radford, J.R. Powers, L.T. Shale, Hughes Christensen; M.A. Jenkins, INTEQ.

Well known in the oil and gas industry, when drilling with concentric hole openers, is the importance of understanding drilling system vibrations and bit hole opener weight transfer. A field testing program was carried out on a full-scale experimental test rig in Oklahoma with known lithology, in order to evaluate concentric underreaming system designs in a controlled environment. The hole-opening system is taken to mean the bit, drive system and concentric hole-opening element.

To fully understand how the system interacts with the formation and reacts to inputs from the surface, drilling mechanics measurements were taken above and below the reamer element. Drilling dynamics measurements were also taken at three places in the BHA, with two drilling dynamics packages spaced out below the hole-opener and one positioned directly above it. That way, dynamics on the bit



IADC/SPE 112670: Rotary steerable system underreamer assemblies are often challenged with BHA instability.



IADC/SPE 112785: Fixed blade multi-diameter reaming tools have been developed to use within rotary steerable assemblies.

and reamer could be studied separately, in order to understand how their relative performance affect each other and the overall system dynamics. A concentric hole enlargement tool, new to the drilling industry, was used in both wells as a part of this study and will be described.

IADC/SPE 112731

Optimization of Deep Drilling Performance With Improvements in Drill Bit and Drilling Fluid Design. A.D. Black, TerraTek; R.G. Bland, Baker Hughes, D.A. Curry, L.W. Ledgerwood III, Hughes Christensen; H.A. Robertson, A. Judzis, TerraTek; U. Prasad, Hughes Christensen; T. Grant, U.S. Department of Energy.

The cost of deep drilling is dominated by the rate of penetration (ROP). Previous studies have shown that ROP usually falls with increasing borehole pressure, but these studies did not probe pressures characteristic of deep drilling. As part of the US Department of Energy (DOE) Deep Trek joint industry program, industry partners and DOE successfully completed full-scale laboratory testing of drill bits and HPHT drilling fluids at 10,000-psi borehole pressure, substantially higher than any previously studied.

The results of the benchmark drilling program using bits and muds in current use, Phase I, were reported earlier (SPE/IADC 105885). This paper presents results and analyses, in terms of ROP and specific energy, from a second round of testing. It identifies factors limiting ROP at great depth and investigates experimental and less conventional drilling fluid systems and bit designs to improve deep drilling performance.

IADC/SPE 112579

Results From Systematic Rotary-Steerable Testing With PDC Drill Bits Depict the Optimal Balance Between Stability, Steerability, and Borehole Quality. S. Jones, J. Sugiura, Pathfinder Energy Services; S.P. Barton, ReedHycalog.

There is significant discussion concerning what type of rotary steerable system (RSS) provides the best quality hole, and which key characteristics of the drill bit, along with a particular RSS, will produce the optimal balance between stability and steerability in directional wells. Although some evidence can be drawn from field performance with various tools and customized drill bits, these results can often be inconclusive due to the large variance in factors involved with commercial drilling.

This paper describes an extensive series of test wells drilled in a controlled and non-commercial environment, allowing single-step changes in both the drill bit features and rotary steerable configurations. The testing is unique in that the specific RSS works in field configurable point-the-bit and push-the-bit modes. Between two distinct RSS operation modes, consistency in stiffness, weight, force applying capability, and control systems lead to a direct comparison of bit performance.

A unique sensor system, integrated into the specific RSS, provided real-time measurement of near-bit borehole caliper and near-bit stick slip and vibration. This feature allowed real-time evaluation of bit and BHA stability and borehole quality. After each test run, memory data was retrieved and used for more detailed assessment of bit performance.

Drill bit tests were systematically structured in a controlled environment so that the relationship between gauge geometry and configuration could be examined without alteration of the cutting structure. As a result, comparison between stability, dogleg capability, torque and drag, and borehole quality was solely dependent on gauge length and geometry. Further, the systematic testing lead to the conclusion that a specific gauge design related to effective side cutting and gauge stabilization is crucial for optimized rotary steerable drilling in both point-the-bit and push-the-bit configurations.

IADC/SPE 112641

Re-examination of PDC Bit Walk in Directional and Horizontal Wells. S. Chen, Halliburton; G.J. Collins, ConocoPhillips; M.B. Thomas, Halliburton.

The phenomenon of left-hand PDC bit walk in directional wells is widely recognized in the drilling industry, with various numerical models developed in recent years showing that left-hand PDC bit walk increases with bit gauge length. However, in Alaskan horizontal wells where formations are soft, long-gauge PDC bits exhibit strong right-hand walk. Designed for and used with a point-the-bit rotary steerable system, these extended gauge bits have exhibited walk rates as high as 5°/100 ft in some cases, and the RSS tool could not steer back to the planned path. Previous bit walk models failed to explain this phenomenon, and the problem was not solved by changing the PDC bit cutting structure.

The paper describes a new PDC bit walk model and its applications in these Alaskan horizontal wells. The model calculates bit walk rate and walk force

in the consideration of bit gauge geometry, hole size, formation compressive strength, steer mechanism of the RSS, bit rotational speed, penetration rate and dogleg severity.

Application of the model recommendations to recent wells is shown to have successfully eliminated the right-hand bit walk and significantly increased bit steerability.

Technical Session: Directional and Extended-Reach Drilling

IADC/SPE 112536

Extended-Reach Drilling—Offshore California: An Operator's Experience with Drilling a Record Extended-Reach Well. M.W. Walker, ExxonMobil.

The "Spanish Bay" well was drilled from a production platform located offshore California in 1,075 ft of water. This record extended-reach well reached 33,435 ft MD / 7,663 ft TVD (29,720 ft vertical section). This paper will highlight the rig limitations, describe design and operational challenges, show how the challenges were addressed, and describe key/unique operations.

Operators often build custom rigs or perform significant upgrades to meet the specific technical requirements for ERD applications. While selected upgrades were required, in this case the operator was limited to using mostly existing equipment while simultaneously dealing with offshore logistics and producing platform space limitations to achieve the objectives of this extended-reach well.

Challenges successfully overcome include limited hydraulics, high torque, pipe racking constraints, mud handling capacity, offshore logistics, and platform space limitations. As predicted by detailed torque and drag modeling, the well's 86° tangent angle required drill pipe to be rotated into the hole to overcome the effects of negative weight. The 9 5/8 x 10 3/4 in. intermediate liner was successfully floated and rotated to 29,831 ft MD / 5,525 ft TVD. The well established a new North American ERD record and a new global ERD record from an offshore location.

IADC/SPE 112586

Horizontal Extended-Reach Re-Entry Drilling of Sidetracks at Sakhalin Island Increases Oil Production From Mature Oil Fields. M.L. Drnec, I. Przegalinsky, Schlumberger.

Re-entry drilling represents a significant part of the current and future drilling activities worldwide and particularly in the Russian Federation. Enormous funds of old oil and gas wells drilled in the last century are inactive. Economical demand positions sidetracking activities with a very promising future. A Russian oil company, famous for successful development of challenging ERD projects at Sakhalin Island, has about 1,000 oil wells drilled between 1950 and 1980, with most of them currently idle. This paper presents a study of the feasibility of drilling horizontal extended-reach sidetracks to increase oil production from these mature oilfields. Its main objective is to evaluate technical and economical aspects associated with drilling horizontal re-entries from already existing old oil well stocks. The objectives of the paper are: evaluation of the economical attractiveness of such a project; candidate selections; drilling engineering design of the wells; evaluation and selection of contractors for provision of appropriate re-entry equipment such as whipstocks, scrapers, mills, bi-centered bits, etc; subsequent coordination between proposed and involved parties; and evaluation of the well placement approach implication.

IADC/SPE 111647

Complex Extended-Reach Drilling to Exploit Reservoirs in Environmentally Sensitive Area Offshore California. G.P. Hertfelder, Plains Exploration and Production Company; M. Menge, M. Patel, J.P. Ruszka, INTEQ.

The marine environment offshore California is an environmentally sensitive location. To minimize environmental impact, platforms installed in the 1980s continue to be utilised for field development without the requirement to install additional jackets or disturb the seabed with subsea completions and flow lines. As the field developments continued, ERD techniques were developed and employed to exploit the outer reaches of the fields and develop new satellite deposits. In order to fully utilise the capabilities of the existing platforms and as they became



IADC/SPE 112731: Results are available from a second round of testing as part of the US Department of Energy Deep Trek joint industry program on drill bits and HPHT drilling fluids at 10,000-psi borehole pressure — substantially higher than any previously studied.

slot-constrained, ERD sidetracks from existing ERD wells became necessary. Some of these sidetracks required highly complex 3D profiles to reach the new targets. This paper discusses some of the challenges drilling offshore California and how the use of ERD techniques allowed full utilisation of available drilling infrastructure while minimising environmental impact.

IADC/SPE 112644

Total BHA Reliability — An Improved Method to Measure Success. J. Brehme, T. Travis, ExxonMobil.

Mean Time Between Failures (MTBF) has been a traditional measure of downhole equipment reliability. MTBFs of some tools exceed 1,000 hours, indicating downhole tools have become more reliable. In 2005, ExxonMobil Development Company initiated a study on RSS failures, which indicated that globally one in three bottomhole assemblies (BHAs) were pulled because of a failure. These results did not match the MTBF numbers provided from the service sector. More detailed analysis indicated MTBF is a good metric for a manufacturer interested in classifying the statistical reliability of individual components but is not a good metric for measuring success of complex BHAs. As BHA complexity increases, the MTBF of single components must increase in order to maintain existing reliability. We are now tracking the RSS performance by run success. This approach favors a total system strategy where each BHA component is evaluated based on its ability to maximize the reliability of the entire drill string. The goal of the initiative is to have the best tools used in the correct application within drilling parameters that do not exceed the tool design.

IADC/SPE 112599

Remote Operations, the Future of Drilling: Directional Drilling Remote Control. I.A. Gorgone, J.E. Gomez, G. Uddenberg, Schlumberger.

It is well recognized that oil and gas companies have increased the implementation of operation support centers to improve decision-making in real time. They have clearly reduced NPT and improved efficiency. Fortunately, emerging technologies now enable end users to also receive and send intelligent commands while tools operate under downhole conditions. This not only introduced the element of fewer trips but the ability to control them from an office.

Operation Support Centers (OSC) receive varying types of data in real time to optimize drilling. This data is collected while drilling, sent via mud pulse telemetry to surface and then via satellite to required points, confidentially, over existing client networks. The same downhole tools sending petrophysical and drilling data in real time also have the ability to receive commands remotely and confirm using the same telemetry protocol. This paper describes the challenge faced to implement the OSCs, the work process that allows one directional driller and one MWD engineer to oversee several rigs simultaneously, remote control options, infrastructure, communication systems and operating results. A special focus and reference will be made to existing operations in Mexico.

IADC/SPE 112365

Dumbarton Field, UKCS: Rapid Redevelopment of a Complex, Mature North Sea Asset Using New Rotary-Steerable and Geosteering Technologies. U. John, I. Tribe, Schlumberger; J. Manson, A.A. Stewart, M. Pendlebury, E. Ferguson, MaerskOil; K. Melville, D.J. Bourgeois, R. Lepp, Schlumberger.

The Dumbarton Field, operated by Maersk Oil North Sea in Block 15/20, has a number of drilling and well placement challenges that hampered development during the '80s and '90s. These include formation instability, directional drilling control issues and thin complex reservoirs that are poorly imaged on seismic. Reservoir overburden is fast drilling formations with hard stringers. The field pore pressure gradient is at 9.07ppg EMW, but mud density needed for wellbore stability is greater than 11.6ppg. This resultant high overbalance and other issues such as hole cleaning, complex directional profile, ECD management at high ROPs, can lead to inefficient motor drilling. The soft formations also create limitations for push-the-bit rotary steerable systems to deliver the required directional performance to land wells.

A new point-the-bit rotary steerable system with a high dogleg capability has been utilised for successful landing of these wells into reservoir sections without need for pilot holes or mechanical sidetracks. Additionally a new LWD tool that allows monitoring of the distance and direction to formation boundaries up to 15 ft away from the wellbore has been used to proactively guide the wells along the thin oil reservoir units/sands. These tools also enabled the wells to be placed as close to the reservoir roof shales as possible to maximize stand-off from the

waterleg and hence increase overall oil recovery. Distance and direction to boundary data displays are intuitive to interpretation allowing better geo-steering decisions without compromising ROP and drilling efficiency.

Within six months, six wells were delivered, including three sidetracks. All wells penetrated more reservoir sand than prognosed, and all were drilled faster than prognosed. Initial production testing was higher than expectation.

IADC/SPE 111384

Geomechanics Enables the Success of Horizontal Well Drilling in Libya: A Case Study. K. Qiu, Schlumberger; J.G. Felgueroso, G. Lalinde, A. Naas, B.J. Coste, Akakus Oil Operations; J. Fuller, Schlumberger.

Drilling in highly deviated or horizontal wells is prone to instability problems. This paper describes a case study in Libya in which significant difficulties were encountered during the drilling of the first horizontal development well in a field in Murzuq basin. The main hole and sidetrack of the well were lost due to severe drilling problems. A comprehensive geomechanics study was carried out to understand the causes of the borehole failure and to improve mud weight programme and drilling performance for future development wells in the field. The analysis identified that the cause of the major drilling problems was inadequate mud weight while drilling the overlying shale formations in the build-up section. The design of the second horizontal well was optimized based on this study. The well was drilled successfully without problems and ahead of drilling schedule. This case study demonstrated that a comprehensive geomechanics study can greatly improve drilling performance and reduce drilling costs.

Technical Session: Tubulars II

IADC/SPE 111871

Solid Expandable Tubular Technology Applications in Saudi Arabia: Lessons Learned. M. Al-Umran, I. Al-Obaidi, S. Zhou, A. Al-Nassir, Saudi Aramco.

Saudi Aramco started solid expandable tubular technology applications in mid-2003. Since then the company has become one of leading players worldwide in terms of field applications, with a total footage usage of more than 120,000 ft and total about 70 wells installed with solid expandable liners so far.

Benefits of utilizing solid expandable tubular as production liner have been realized by:

1. Reviving dead or poor oil producer to prolific oil producer.
2. Ability to deliver MRC (maximum reservoir contact) wells with extended 5 ½-in. laterals drilled by either slimhole rotary steerable system or directional drilling assembly.
3. Allowing advanced completions, such as smart completion, with interval control valves inside expanded 5 ½-in. liner and slimhole packers and screen to provide zonal isolation in 5 ½-in. lateral or sidetrack aimed to shut off water production as well as inflow control.
4. Allowing advanced completions, such as open hole smart completion, with interval control valves and slimhole packers to provide zonal isolation in 5 ½-in. motherbore aimed to shut off water production as well as inflow control.

However the success did not come without hard lessons learned, including several major expandable liner failures in the most challenging curve section from vertical to near horizontal hole. This paper presents discussion on technology evaluation for sour services; well planning and operational steps; problems encountered in the field; operational procedure improvements; modification of expansion system.

Although the technology no doubt adds a great value to drilling and workover wells, it still requires more improvements before becoming a reliable and regular tool for the application environment for Saudi Aramco.

IADC/SPE 111742

A Design Strength Equation for Collapse of Expanded OCTG. F.J. Klever, Shell.

Expandable tubulars provide exciting new opportunities for well design and construction. This technology has permitted access to hydrocarbons that could not be reached by conventional drilling techniques. Design tools similar to those available for conventional oil country tubular goods (OCTG) are required to facilitate further dissemination and application of expandable tubulars. In particular, equations for performance properties of expanded pipe are needed.

This paper describes the development of an equation for the collapse strength of expanded pipe. It is based on the combination of collapse test data and theoretical modeling, and its statistical approach is fully consistent with the collapse strength formula used for conventional OCTG described in ISO TR 10400 / API Bulletin 5C3.

It is shown that the new equation can model the collapse strength of a general set of expanded pipe

data over a range of pipe diameters and wall thicknesses. The recipe of how to derive the design collapse strength of expanded pipe is also applicable to any particular pipe product that a manufacturer and an end user may wish to qualify for well use. In addition, the new equation takes account of the effect of internal pressure and axial load on collapse.

The API SC5 Resource Group Expandable Tubulars tasked with developing Recommended Practice 5 EX has incorporated the collapse design formula, the details of which are proposed in this paper.

IADC/SPE 112623

Drillstring Solutions Improve the Torque Drag Model. R.F. Mitchell, Halliburton.

The only standard drillstring model in use today is the torque drag model, and because of the simplicity and general availability of this model, it has been used extensively for planning and in the field. Field experience indicates that this model generally gives good results for many wells, but sometimes performs poorly.

In the standard torque drag model, the drillstring shape is taken as the wellbore shape. Considering that surveys are taken within the drillstring, this is an excellent assumption. However, given that the most common method for determining the wellbore shape is the minimum curvature method, the wellbore shape is less than ideal, because the bending moment is not smooth at survey points. This defect is dealt with by neglecting bending moment, but as a result of this assumption, some of the contact force will also be neglected.

If the wellbore shape is the drillstring shape, why not use analytic drillstring solutions to model the wellbore trajectory? Before these solutions can properly interpolate the survey data, they require some modification. This paper shows how this can be done in a simple and efficient way, so that little of the calculation speed of the conventional model is lost. With this new wellbore model, the simple torque drag model becomes a full stiff string formulation.

IADC/SPE 112773

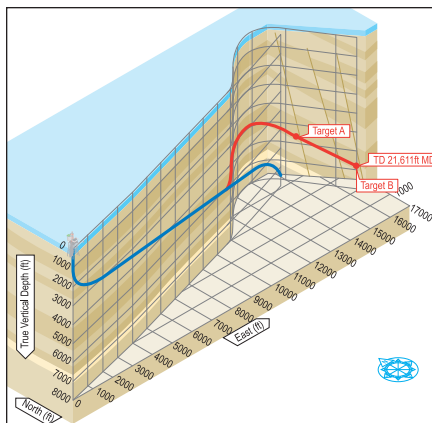
Quick Intervention: Going Lighter and Running Faster With Gastight Rotary Shouldered Connection! R.C. Griffin, G. Plessis, D. Chin, Grant Prideco.

This paper presents the development of an intervention riser that incorporates a modified second-generation rotary shoulder connection. This double shouldered connection features a high-pressure, gas-tight metal-to-metal radial seal, a secondary backup resilient sealing barrier and additional modifications to cope with subsea conditions. The effort to design, test and qualify the intervention riser for operation in offshore Australia is detailed. Results from finite element analysis, laboratory tests, manufacturing processes and field results are presented.

IADC/SPE 112639

Application of Connection Productline Evaluation. J.P. Powers, D. Baker, M.S. Chelf, ExxonMobil.

Proprietary threaded casing and tubing connections are expected to maintain structural integrity and sealability performance throughout the well's life. Industry and company standards for evaluating connection performance via physical testing on specific size/weight/grade combinations have been optimized. The industry now seeks methods to infer performance for combinations that have not been tested, based on completed tests. Time and cost savings are realized by extending test results within a family, compared with multiple individual evaluation programs.



IADC/SPE 111647: In field developments offshore California, ERD sidetracks from existing ERD wells became necessary in order to fully utilise the capabilities of the existing platforms and as they became slot-constrained. Highly complex 3D profiles were needed to reach new targets.

One operator has implemented an approach to evaluating a family of proprietary connection designs across a range of size/weight/grade combinations. This approach includes a comprehensive review of the threading specifications within the family to provide a consistent design approach, finite element analysis of all of the family members within the range under extreme tolerance and load conditions to evaluate the consistency of performance, and rigorous physical testing of combinations representing the boundaries of the range or worst cases within the range.

The operator has confidently assigned performance envelopes for several proprietary connection design families. Physical testing and finite element analysis evaluations assessed design and performance consistency and established specific design family specific performance criteria. This paper will describe the process implemented to provide appropriate performance assessment of a connection product family for which all size/weight/grade combinations were not tested.

IADC/SPE 112571

How Drillstring Rotation Affects Critical Buckling Load? S. Menand, H. Sellami, J. Akowanou, Paris School of Mines; C. Simon, L. Macresy, DrillScan; P. Isambourg, Total; D.C. Dupuis, Pride International.

Buckling of tubulars inside the wellbore has been the subject of many articles. However, these conservative theories have always followed the same assumptions: The wellbore has a perfect and unrealistic geometry (vertical, horizontal, deviated, curved), the friction and rotation effects are ignored, conditions relatively far from actual field conditions. How do tubulars buckle in actual field conditions, that is, in a naturally tortuous wellbore with friction and rotation? Can we apply conservatively theories developed for perfect well conditions (no tortuosity, no friction, no rotation) to actual well conditions?

This paper presents how the drillstring rotation affect the critical buckling load in actual field conditions. These new results have been obtained from an advanced model dedicated to drillstring mechanics successfully validated with laboratory tests. These results should significantly improve well planning and operational procedures to drill and operate more and more complex wells.

IADC/SPE 112720

Tight Clearance Operations—Running 5 1/8-in. Liners in 5 7/8-in. Holes. M. Goertz, K. Belohlavek, ExxonMobil.

In North German gas fields, occasionally 5.5-in. liners have to be run in 5.875-in. boreholes. This low clearance application does not represent the standard. This paper describes steps taken to successfully run and cement these liners in spite of the extremely tight clearances.

One application is to run 5.5-in., 32-lbs/ft thick wall casings in 5.875-in. holes to cover squeezing salt sections in order to provide long-term integrity of the well. The other application is to run regular 5.5-in., 20-lbs/ft casing to enable remedial sand control, which would not be possible with standard sized 5-in. or 4.5-in. liners.

In both applications, these liners had to be run through 5.875-in., driven by the drift diameter of the prior set 7-in., 35-lbs/ft liners, into a directionally drilled 5.875-in. open hole with high dogleg severities. Often the drilled sections contained hard and abrasive sandstone layers, which have to be drilled with impregnated bits. Thus, underreaming is not economically viable.

To successfully run and cement the 5.5-in. liners, the borehole has to be prepared properly by running extremely stiff reaming assemblies. The 5.5-in. tubulars have special flush connections. Experience shows that a planned DLS of 6°/100 ft is feasible. In addition, centralization has been changed from special bow type centralizers to Protech CRB7 Ceramic Carbon Fibre Standoffs. The mud systems covers a range of properties, from low solid formate mud to weighted water-based mud. Additionally, to reduce friction, lubricants based on Glycol or Graphite were successfully applied. Finally, cement recipes have to be carefully adjusted to these mud systems.

IADC/SPE 112302

New Equipment Designs Enable Swellable Technology in Cementless Completions. H.E. Rogers, D. Allison, E. Webb, Halliburton.

In the oil and gas industry, it is a common practice to install production casing through producing formations with cement providing the primary inter-zonal isolation in the annulus. Inadequate displacement efficiencies, fluid contamination and loss-circulation intervals sometimes limit cementing operations ability to provide sufficient zonal isolation to prevent annular communication over the life of the well. Formation damage caused by cementing operations can also adversely affect life of the well production capabilities.

New completion technologies using swellable elastomers can be an alternative to cementing operations performed over producing formations. However, conventional floating equipment has limited the application of swellable elastomers in some completion operations. Specifically, in non-cemented completions where swellable elastomers provide the only annular barrier, a mechanical seal is required at the toe of the production casing that has a service life equal to the life of the well under downhole conditions. This paper describes the benefits of swellable elastomers used alone and in combination with cement to provide life-of-the-well zonal isolation.

Technical Session: Case Histories

IADC/SPE 112631

Shallow Hazards Planning in Nigeria Deepwater — Erha 7 Well. E.M. Garcia, T.J. Akers, J.L. Holster, ExxonMobil.

The Erha 7 well is a deepwater exploration well that was ultimately drilled with a dynamically positioned rig in 1,074 m water depth within Nigeria's Offshore Mining License (OML) 133 (formerly OPL 209). During the early well planning process, the site investigation team identified numerous, extensive shallow hazards stacked in the area surrounding the Erha 7 geologic targets. These hazards were evaluated by the drill team, site investigation team, and the business unit to optimize the well location and minimize the risk of encountering shallow gas charged sands. The final well location allowed vertical drilling of the riserless conductor hole interval and required directional drilling below the conductor to intersect vertically stacked geologic targets. Because of the close proximity to numerous shallow hazards and the limited seismic resolution, the final well location was still deemed to possess a moderate risk of encountering gas charged shallow sands.

This paper discusses the shallow hazards planning involved with the Erha 7 deepwater well. It summarizes the limited industry experience regarding deepwater shallow gas flows and the associated safety considerations. The paper presents the modeling and evaluation of shallow gas flows and dynamic kills used to quantify the potential benefits of drilling a pilot hole, and discusses the sensitivities associated with performing an effective dynamic kill. Finally, a discussion of the dynamic kill plans developed to prevent and effectively mitigate a shallow gas flow is presented as a model for approaching future shallow hazards.

IADC/SPE 112161

Subsea Production Enhancement — Success and Failure Over 5 Years. E.M. McGennis, Well Operations (UK) Limited.

Subsea well intervention has been around in the North Sea for many years, but in the last five

years it has taken off due to a combination of high oil price and aging wells. This paper will look at the actual results achieved with production enhancement work done in subsea wells across the UK sector of the North Sea over a five-year period of 2000 to 2005. This time frame allows the results to be seen in the context of longer term field value. All work included in the paper was done rig-less with a specialist subsea well intervention vessel. The work done was through tubing and included zone isolation and re perforation.

The paper will detail the production profiles of the wells both before and after the intervention work along with a discussion of the work done and an explanation of the factors that influenced the final result both good and bad.

IADC/SPE 112633

Successful Drilling Management of Mass Transport Complexes (MTC) in Deepwater Angola. B.A. Elieff, C. Page, V. Gupta, ExxonMobil.

Esso Exploration Angola (Block 15) Limited, along with concessionaire Sonangol and co-venturers Eni, BP and Statoil, are developing several Angola Block 15 fields in water depths of up to 1,400 m. Many of the Block 15 wells have encountered unstable shale sections defined as mass transport complexes (MTC), particularly wells drilled from the Kizomba B platform in the Kissanje field. Several of these wells have experienced wellbore instability events that resulted in drilling-related problems such as pack-offs, excessive drag during trips, stuck pipe and the inability to run casing to TD. Of the initial five wells drilled from the Kizomba B platform, three sections were sidetracked due to wellbore instability related hole problems.

The MTC sections encountered while drilling in the Kissanje field have been identified as the root cause

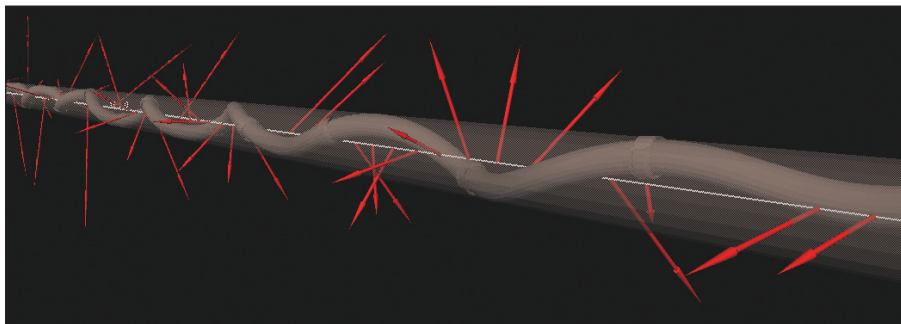
of the hole quality issues that resulted in unplanned sidetracks. Esso, along with the ExxonMobil Upstream Research Company, undertook a study to better understand MTC characteristics and the associated drilling tools and practices required to effectively manage wellbore instability in long MTC sections. The revised drilling practices, along with the well specific wellbore stability model, have resulted in an improved success rate for effectively managing wellbore instability while drilling and running casing in these intervals.

IADC/SPE 112616

Troll West Oilfield Development — How a Giant Gas Field Became the Largest Oil Field in the NCS Through Innovative Field and Technology Development. R.D. Jones, StatoilHydro; E. Saeverhagen, A.K. Thorsen, S. Gard, INTEQ.

The Troll West oilfield has been and still is developed with more than 110 horizontal subsea wells, including 53 multilateral wells (MLT). Several of the MLT wells have, over time, been designed and drilled with multiple open-hole sidetracks to increase drainage area for each wellhead. The field has been developed from the first test wells drilled in 1984 and 1986, with oil production on stream in 1994 and continuous development still ongoing. The commercial oil reserves on the field have gone from 0 in 1986 to more than 1,400 million bbl today.

To be able to achieve this tremendous economical upside, the thin oil rim has been developed through subsea development and extensive horizontal drilling enhancement. The latest development is through extensive use of multilateral drilling and wells containing up to 7 horizontal branches. The process of drilling the MLT wells and the benefit and risk evaluation for the MLT process is discussed and illustrated in this paper.



IADC/SPE 112571: Results from an advanced model dedicated to drillstring mechanics show how drillstring rotation affects the critical buckling load in actual field conditions.

This paper also shows how the field and technology development has evolved over the last two decades and plans going forward to continue strengthening the Troll West Oil Field production for another 15-plus years prior to the gas drainage.

IADC/SPE 112708

Successful Development Drilling of an HP/HT Infill Well in a Highly Depleted Reservoir: Case Study. L. Fambon, G. Joffroy, TOTAL.

Drilling infill wells on HPHT fields after a significant depletion has occurred represents a real challenge. It requires drilling from a cap rock remaining at or close to virgin pressure into a reservoir in which pore and fracture pressures have largely decreased due to production. No mud weight window exists anymore at the transition between cap rock and reservoir. The difficulty is further increased by uncertainties in the pressure profile along the well path, the rock mechanics and their change generated by the high and rapid depletion, and also by depth uncertainty on the top reservoir. For this reason, most HPHT fields are developed by drilling all wells before a pre-defined limit of depletion level is reached at which the mud weight window closes. This limit is usually low.

However, HPHT producer wells face depletion related threats to their integrity, such as sand production and deformation of the production liner under rock movement. When these threats become effective, the well and its associated production will be lost. Replacement wells will need to be drilled. Additional wells are also needed to increase reserves by creating new off-take points. This paper describes the preparation work performed before drilling an HPHT infill well in a highly depleted reservoir, the management of uncertainties during the drilling, and some of the lessons learned from this first experience.

IADC/SPE 111441

Connector Conductor Wells Technology Achieve High Profitability Through Multiwell Bores and Downhole Connections. S.M. Al Khodhori, Petroleum Development Oman; H. Al-Riyami, P. Holweg, Shell; J. Wright, John Wright Company.

Brunei Shell Petroleum Company has successfully implemented a first worldwide technology application known as Connector Conductor Wells. The Connector Conductor wells concept consists of two parts: the Conductors and the Connectors. The Conductors are horizontal wellbores drilled within the oil rims and abandoned above reservoir sections. The Connectors act as horizontal flow conduits within the reservoir, and the production to surface takes place through dedicated Connector wells. The Connector wells are therefore designed to connect several conductor wells and to provide the completion equipment to surface.

A field trial was successfully implemented in

February 2007. A land well was drilled horizontally to intersect and connect with an offshore well at Seria North flank field. Hydraulic connection between the two wells has been achieved within expected production. The Connector Conductor wells project is the first of its type to successfully complete worldwide.

The project had moved through various serious technical and logistic challenges. Those challenges could have only been overcome through extensive sessions and efforts of multi-teams and parties in BSP, Shell SIEP teams and service companies. Success of the Connector Conductor wells project in Darat proved the technical feasibility of the concept for wider implementation across BSP fields and Shell assets.

IADC/SPE 111129

A Case-Based Approach to Understand the Complexity of Causal Connections Related to Well Integrity Problems. J. Abdollahi, I.M. Carlsen, P. Randhol, SINTEF Petroleum Research; E. Tenold, H.B. Haga, T. Jakobsen, StatoilHydro.

Well integrity challenges are a growing concern to operators worldwide and impact the overall recovery of the fields. Sustained production from mature fields plays an increasing role in energy demand. The well life cycle suffers from lack of well integrity mostly due to leaks and loss of pressure barriers and is a key challenge when needing to change the use of the wells for improved oil recovery. Diagnoses, localization and handling of different kind of leaks need a special approach to overcome a very complex picture. A huge amount of data need to be addressed and include changing operational histories and different well components.

This paper discusses a case-based reasoning methodology to diagnose different well leaks with different causes in order to diagnose well integrity. Researchers at SINTEF Petroleum Research have assisted Hydro in their work to understand the causal connections of leaking wells at the Norwegian Continental Shelf. Hydro's database, including both leaking and non-leaking wells, has formed the basis for this work. A chronological documentation of the well activities, observations, actions and outcomes during well life cycle has been studied.

IADC/SPE 112610

Remote HPHT Wells in Egypt. T. Bruce, Pride International.

BP drilled and tested successfully the well Raven 1 in 2004. In 2006, BP mobilized into Mediterranean Sea the 15K moored semi Pride North America. The wells to drill are deep, HPHT exploration wells; it is the first big bore wells introduced in Egypt. Extensive learnings from the Gulf of Mexico and Shah Deniz were transferred over.

The result of well Raven 2 confirmed the gas

resources and the success of the design and the execution of a big bore well. The leanings are: successful application of stress cage principle, underreaming performance, ECD management, well control equipment and operations, expendable contingencies actually used, equipment integrity standards. Specialized equipment was implemented, and personnel training was a key issue. A joint operations manual was created and strictly adhered to. The paper will outline the challenges, how the technology was implemented, equipment and procedures.

Technical Session: MPD/UBD

IADC/SPE 112651

Successful Implementation of First Closed Loop, Multiservice Control System for Automated Pressure Management in a Shallow Gas Well Offshore Myanmar. P.D. Fredericks, D. Reitsman, At Balance; T. Runggai, N. Hudson, Petronas; R. Zaeper, O. Backhaus, INTEQ; M. Hernandez, IntelliServ.

In their plans to explore the shallow gas potential of the Nagar prospect offshore the southern coast of Myanmar, Petronas Carigali had to contend with a number of potentially high-risk scenarios. The shallow nature of the hazardous prospect made kick detection speed and pressure control accuracy essential to avoid losing returns.

Concerns about a weak casing shoe, a narrow drilling margin, the inability to circulate out gas and control bottomhole pressure (BHP), and a short response time drove Petronas to find a solution to drill the shallow gas bearing sands safely, from a moored drill ship using conventional subsea equipment.

Petronas estimated that within a minute the system would have to detect and shut in gas influx, continuously maintain flow to circulate it out, and accurately manage the BHP of a flowing, multiphase fluid within safe limits. They concluded they could drill Nagar only with a pressure management system that would maintain BHP within about 15 psi while drilling and about 40 psi during connections and well control.

In their search, Petronas learned that no system existed with the functionality they needed. But, by electing to combine new and existing technologies from three providers, they were the first to develop one that did. Their solution involved integrating technology for automated pressure control, pressure while drilling (PWD), and high speed, drill string telemetry. Modifications had to be made to the pressure control and PWD systems to provide the necessary functionality. Given the safety critical nature of the drilling hazards the modifications and system integration were tested during simulated kicks before drilling out the casing shoe. During testing on the rig and drilling operations the integrated system proved its ability to maintain a near constant BHP, with the accuracy and speed Petronas needed to safely and successfully drill the Nagar prospect.

IADC/SPE 112662

Managed Pressure Drilling Success Continues on Auger TLP. M.J. Chustz, Shell; L.D. Smith, Sigma Engineering; D.M. Dell, At Balance.

Shell E&P continues to successfully execute redevelopment slimhole sidetracks using MPD on the Auger TLP in deepwater Gulf of Mexico. Two wells have been successfully drilled and cased utilizing MPD, and a third well is in progress. MPD execution continues to improve, resulting in efficiency gains and access to previously unattainable reservoir targets. Open-hole sections once considered impossible to drill due to depletion-induced frac gradient reduc-

tion and instability are being drilled trouble-free with MPD.

Auger field redevelopment history, well designs and managed pressure drilling designs will be reviewed. Execution of MPD operations will be addressed in detail, focusing on engineering and operational achievements and improvements throughout the three well MPD campaign.

IADC/SPE 112761

Simulations Comparing Different Initial Responses to Kicks Taken During Managed Pressure Drilling. A.K. Das, Blade Energy; J.R. Smith, Louisiana State University; P.J. Frink, Blade Energy.

An industry-supported research project to establish a basis for comprehensive, reliable well control procedures for MPD operations has begun. This paper will describe the results of a simulation-based study comparing alternative initial responses to a range of kick scenarios. The primary responses considered were increasing casing pressure while continuing circulation, increasing the circulating rate without increasing casing pressure, and shutting in the well conventionally. These were investigated using a transient, multi-phase flow simulator.

The purpose of the study is to provide a basis for determining the most effective initial response for controlling a kick taken during MPD, considering both the risk and the consequences of losing returns.

A significant but still tentative result of this on going study is that there may be no single best initial response to a kick taken during MPD. The best response may depend on well geometry, kick zone productivity and likelihood of lost returns.

IADC/SPE 112779

Offshore Underbalanced Drilling — The Challenge at Surface. G. Gough, Weatherford; R.A. Graham, DONG Energy.

This paper is a case study detailing the process followed and challenges encountered, at surface, when drilling oil wells underbalanced offshore Denmark. UBD was identified as an enabling technology in the Syd Arne field to combat conventional drilling challenges due to variations in pressure profile along lengthy horizontal hole sections. The drilled wells comprised 6-in. horizontal sections in excess of 2,000 m.

The drilling programme presented a significant examination of the surface-handling equipment due to the anticipated inflow parameters. The surface system was required to de-energise and separate up to 25,000 bpd returned/produced oil, water and cuttings along with up to 30 MMscfd of gas; returning the water back to the rig for the well circulation system, cuttings into the annulus of an existing well and the routing of produced hydrocarbons to the Syd Arne production platform.

The first well also utilised platform gas for annular gas injection to maintain the required circulating pressure profile. A rigorous process design procedure was followed to determine the optimum surface equipment configuration to handle the combination of drilling fluid, solids and well effluent expected at surface during underbalanced drilling operations. This also allowed for the evaluation of the potential for hydrate formation, foam and emulsions. In addition, a strategy was employed to facilitate recovery of oil and gas produced during underbalanced drilling operations to the platform process facilities.

IADC/SPE 112739

MPD Operation Solved Drilling Challenges in a Severely Depleted HPHT Reservoir. K.S. Bjørkevoll,

D.O. Molde, R. Rommetveit, SINTEF Petroleum Research; S. Syltøy, StatoilHydro.

A novel MPD setup was tested and used to make possible the drilling of an 8.5-in. hole through reservoirs with heavily depleted zones. The paper describes briefly the operations and discusses challenges and experiences related to making complex components work reliably together. Challenges exceeded expectations, but after a test period with many improvements based on trial and error in cased hole, the 8 1/2-in. section was drilled successfully with good pressure control.

Technical Session: Advanced Telemetry and Real-Time Support

IADC/SPE 112533

Automatic Real-Time Drilling Supervision, Simulation, 3D Visualization and Diagnosis on Ekofisk. R. Rommetveit, K.S. Bjørkevoll, SINTEF Petroleum Research; S.I. Ødegaard, Hitec Products Drilling; M.C. Herbert, ConocoPhillips; G.W. Halsey, SINTEF Petroleum Research.

eDrilling is a new and innovative system for real-time drilling simulation, 3D visualization and control from a remote drilling expert centre. The concept uses all available real-time drilling data (surface and downhole) in combination with real-time modeling to monitor and optimize the drilling process. This information is used to visualize the wellbore in 3D in real time. eDrilling has been implemented in an Onshore Drilling Center in Norway, and the system has been used on several drilling operations. Experiences from its use will be summarized and presented; both related to technical and work process issues.

IADC/SPE 112636

High Speed Telemetry Drill Pipe Network Optimizes Drilling Dynamics and Wellbore Placement. T.H. Ali, M. Sas, J.A. Hood, S.R. Lemke, A. Srinivasan, INTEQ; J. McKay, K.S. Fereday, C. Mondragon, S.C. Townsend, S.T. Edwards, BP; M. Hernandez, M. Reeves, IntelliServ.

This paper discusses the successes and lessons learned during North America's first deployment of wired pipe telemetry with a rotary steerable system and triple combo suite. The paper details the operational experience while drilling a horizontal lateral with an emphasis on drilling optimization and LWD processing; given the availability of memory data real time via wired pipe telemetry.

Recent advances in logging while drilling technologies call for broader bandwidths and faster telemetry data rates for optimum utilization of data available downhole. There has also been a remarkable development of downhole drilling dynamics and optimization tools. To cater to the demands for higher telemetry rates, wired pipe telemetry has set a paradigm for the industry by its capabilities to deliver real-time memory data (up to 2 megabits/sec).

IADC/SPE 112702

The Utilization of the Massive Amount of Real Time Data Acquired in Wired-Drillpipe Operations. T.S. Olberg, H. Laastad, StatoilHydro; B. Lesso, A. Newton, Schlumberger.

Drilling data telemetry rates with the current mud pulse systems presents a bottleneck to users of downhole drilling data. Wired drill pipe (WDP) telemetry allows for a several orders of magnitude increase in data transmission rates. Statoil tested WDP while drilling a horizontal well from the Visund platform in the Norwegian North Sea. There were

two aspects to this test. First, the hardware and process operation of the wired drill pipe with a full range of MWD and LWD tools, and second, the use of this data by a multi-disciplinary team in real time to turn data into information so that better drilling decisions could be made.

More than 200 words of downhole formation evaluation, wellbore and drilling mechanics data from WDP telemetry were combined with standard surface drilling and depth data for transmission from the platform to an onshore support center. The WDP Enhanced Decision Team with expertise in geomechanics, petrophysics, geology, structural modeling and drilling mechanics was deployed in a passive test mode adjacent to the center. The nature of the test was that the group could not directly make decisions but could make recommendations to the Visund operations team.

Several value cases were identified during the test, which could be broadly categorized into HSE, improved drilling operations, well placement and data transmission. The most obvious and immediate benefit of WDP technology was identified in the areas of fast downlinks and control of downhole tools. High-frequency, time-based data was also useful for real-time torque and drag analysis and borehole quality using real-time caliper data. Better monitoring of downhole formation and wellbore pressures provided a basis for improved well control and borehole stability. On the other hand the ability to send significantly more curves with higher resolution enhanced the well placement/geosteering process.

IADC/SPE 112742

A Step Change in Total System Approach Through Wired-Drillpipe Technology. V. Nygard, M. Jahangir, T. Gravem, E. Nathan, INTEQ; J.G. Evans, Hughes Christensen; M. Reeves, IntelliServ; H. Wolter, S. Hovda, StatoilHydro.

The demand for increased oil and gas recovery requires the drilling of complex extended-reach wells with optimized reservoir exposure for production and minimized overall production costs. In order to achieve these objectives, the use of high-end drilling and logging technology to optimize well placement is of essence. However, the optimal utilization of this technology is often limited by the real-time transmission bandwidth of essential data from and to the downhole tools. The introduction of wired pipe technology has facilitated a step-change in two-way data communication, resulting in a high-speed data transmission giving much greater volume, resolution and quality of formation evaluation data and drilling dynamics data. Furthermore, the direct control of rotary steerable tools has been enhanced to allow instantaneous programming changes and better utilization of dynamics data to enhance the decision-making process required to address drilling dysfunction challenges, hole quality, gross ROP and BHA reliability.

The high bandwidth technology was used while drilling two laterals on the Troll field's reservoir in the Norwegian North Sea in 2007. The memory quality data was transferred through wired pipe to surface while geosteering through relatively unconsolidated sandstones with localized zones of hard calcite cementation.

The adoption of a Total Systems Approach to select the ideal combination of application specific drill bit, drilling system and appropriate procedures and practices was presented and discussed in SPE paper 99122 ("Mitigation of Application Specific Challenges Through a Total System Approach"). Realizing the full benefit of the approach has been hampered by bandwidth restriction and time lag associated with conventional mud pulse telemetry. This paper will discuss how wired pipe technology has been utilized to enhance the Total System Approach concept dur-

ing the first tests and how it will affect the way we operate going forward.

IADC/SPE 112683

A New Mud-Pulse Telemetry System for Enhanced MWD/LWD Applications. C. Klotz, P.R. Bond, I. Wassermann, S. Priegnitz, Baker Hughes.

Mud pulse telemetry systems in drilling operations have enabled the industry to gather valuable directional and formation data while drilling the well and to optimize the drilling process. This makes drilling operations more cost-efficient and allows the drilling of complex wells. In recent years, new LWD technologies have dramatically increased the amount of information collected downhole. This increasing demand for real-time bandwidth is a major challenge for conventional mud pulse telemetry, which has data rates that are normally below 3 bits/sec.

This paper describes a system for downhole-to-surface mud pulse telemetry that uses discrete or modulated pressure signals generated by a novel mud pulser design and a surface data acquisition unit with advanced signal processing capabilities. The new system is able of handling the complex and continuously varying properties of the transmission channel (the pipe bore filled with flowing drilling mud) by optimizing the transmission signal and the surface processing algorithms in realtime. Under a given scenario, higher data rates can be achieved that, from a log quality standpoint, result in high log densities for improved realtime decision making.

The new system has been successfully run in field trials in the United States, Norway, Brazil and Saudi Arabia. During these deployments, data rates could be substantially increased compared with previous offset runs. The focus in this paper will be on a description of the system and its impact on both MWD and LWD realtime services.

Technical Session: Deepwater II

IADC/SPE 112787

Design and Qualification of Critical Landing String Assemblies for Deepwater Wells. A.J. Cantrell, T H Hill Associates; C.N. Beiriger, Chevron; D. Everage, B.L. Hubbard, TH Hill Associates.

Qualification of landing strings has become a major concern for oil industry operators as longer and heavier casing, tie back or liner sections are required in deepwater and ultra-deepwater wells. Total buoyed weights are currently approaching two million lbs, making it imperative that every component in the landing string assembly is properly qualified. Any process which qualifies a landing string assembly must be multi-faceted, consisting of both design verification and a subsequent "fit for purpose" inspection. Experience has proven this approach is absolutely necessary to confirm all design assumptions hold true. Over the past six years, a systematic, field-proven and reliable qualification process has been developed to allow operators to successfully land assemblies with buoyed weights up to 1.6 million lbs in water depths from 2,850 ft to almost 9,000 ft on semisubmersible rigs and drillships.

This process addresses critical design considerations, such as verification of specialty tool ratings, the effect of makeup torque on connection capacity, appropriate usage of existing slip crushing calculation methods, heave induced dynamic loading, and minimizing the probability of darts becoming lodged in the assembly. Inspection issues addressed include coverage and scheduling, traceability to ensure accurate material properties are used in all design calculations, full length ultrasonic testing of the drill

string, and proper inspection of components which are routinely inspected incorrectly.

This paper details the most relevant aspects of this field proven process, and reviews the implementation of this process by an operator for use on a broad range of casing and liner landing operations.

IADC/SPE 112630

Improving Hole Quality and Casing-Running Performance in Riserless Topholes—Deepwater Angola. T.J. Akers, ExxonMobil.

The operator and co-venturers are developing several Angola Block 15 fields in water depths of up to 1,400 m. To date, 83 development wells and 33 exploration and appraisal wells have been drilled in the block. Most have experienced hole quality issues in the riserless interval that manifests themselves as tight hole while tripping the BHA and abnormal/excessive drag running casing. In a few cases, casing could not be run to TD, and in one case, the casing buckled in open water.

There has been uncertainty as to the root cause of the hole quality issues. A review of available literature revealed very little published information on riserless drilling and casing running practices. The operator undertook a study of its riserless drilling and casing running practices in order to look for trends that may suggest certain sources as the root cause and to allow a re-examination of long accepted practices. The study, combined with some new perspectives on directional drilling mechanics and drilling fluid selection, has identified potential root causes not previously considered.

IADC/SPE 112788

Surface BOP System for Subsea Development Offshore Brazil in 1,900 m of Water. B.A. Tarr,



IADC/SPE 112662: Shell E&P continues to successfully execute redevelopment slimhole sidetracks using MPD on the Auger TLP in deepwater Gulf of Mexico. Above, MPD equipment is tested for offshore use.

T. Taklo, A. Hudson, L.A. Olijnik, H. Shu, Shell; R. Greff, Transocean.

A surface BOP system with a seabed isolation device (SID)1 was successfully used to extend the water depth capability of the DP semi Stena Tay for exploration drilling activities in ultra-deepwater to 2,887 m offshore Brazil and to 2,447 m offshore Egypt in 2003. This provided the necessary experience to take the next step towards reducing the cost of deepwater developments utilizing a surface BOP system deployed from an earlier-generation, lower-specification deepwater rig.

This paper presents the configuration and specifications developed for the surface BOP drilling and subsea completion system to be deployed offshore Brazil in the first phase of the Parque das Conchas development that encompasses several reservoirs in up to 2,000 m of water. The rig selected for the project had to meet certain minimum requirements to safely deploy the planned surface BOP system and these requirements led to the selection of the GSF Arctic I. New elements incorporated in the surface BOP system include: site-specific pre-laid polyester taut leg mooring system configuration; slim bore wellhead system (to land production casing hanger); purpose-built 16-in. OD high-pressure riser system (to replace casing riser); added pressure test hose line, strapped to riser (to pressure-test tubing hanger and packer); replaced lower shear ram in SID with fixed 7 5/8-in. pipe ram (to seal on slickjoint); added power and hydraulic lines in SID umbilical (to reduced ROV support needed); vertical subsea tree, tubing head spool and slim-bore tubing hanger with hydraulic running tool.

Development drilling operations with this surface BOP system are expected to begin in 1Q 2008.

IADC/SPE 112388

PRD12,000 Drill Ship: Increasing Efficiency in Deep Water Operations. B. Fossli, Ocean Riser Systems; S.M. Hendriks, GustoMSC.

In the deepwater environment, large and expensive-to-operate 5th-generation drilling rigs are utilized to drill exploration wells, drill development wells, perform completion activities and intervene/work over development wells. In the current market, with spiraling dayrates, new drilling systems and improved functional specifications have been incorporated into a newbuild vessel of a reduced size, with improved capabilities and with functional specifications that

will make drilling and workover/intervention of subsea wells more efficient and cost-effective against the traditional MODU.

IADC/SPE 112597

Megathyst Units — Operational Optimization With Four Identical Drilling Rigs After 5 Years Of Operation. G. Bocabarteille, D. Dupuis, J. Araujo, Pride International.

The Megathyst class rig design is an evolution of the Amethyst class rig targeted for mid-range deepwater applications in benign environment. Although most rig designs are duplicated many times, they are seldom identical in rig equipment and rarely deployed in the same geographical areas to take advantage of the standardization. A total of 6 Megathyst class rigs were originally planned, specifically for deepwater operations in Brazil for Petrobras and development drilling operations. Because of market conditions, only 4 units were built, and all are deployed in close proximity of each other in Brazil.

This paper describes the benefits of a rig design that was very much influenced by the client and tailored to the client's operational needs. It gives an overview of the unique rig design, specifications and characteristics that favour and are tailored to the clients long-range development programs in the mid-range deepwater areas.

IADC/SPE 112723

Requirements for a Full Drill Through Subsea Wellhead and Tree System. S. Lewis, J.J. Suter, ExxonMobil.

This paper describes the requirements realized in the development of a full drill through subsea wellhead and tree specification. Drill through wellhead and tree systems provide an opportunity for savings in capital and operating expense. Given a target development, definition of requirements determines potential savings, performance and necessary contingencies. Current industry practice considers both slim-bore and drill through wellheads and trees. However, operational interfaces may not be fully apparent.

The case considered is an 18.75-in. wellhead with a 13.625-in. nominal hanger bore. The system interfaces a standard 21-in. outside diameter riser and an 18.75-in. horizontal subsea tree. The full drill through system is capable of drilling out and run-

ning a 10.75-in. casing and installation of the lower and upper completion with the subsea tree installed. Compared with the original horizontal tree and wellhead, the drill through system can potentially reduce well construction by two days. Primary design considerations include the casing program, sequence of operations, protection of seal bores, and primary and contingency operations. Seal surface protection is important for the reduced wellhead bore design. The reduced bore increases the exposure of casing hanger and running tool seal areas. Normally, primary operations take place through the tree; however, contingencies must consider operations without the tree installed. Thorough understanding of the requirements, an optimized drill through system can be achieved.

IADC/SPE 112660

Building and Testing a Battery-Operated Subsea Shut off System. A.S. Bamford, C.A. Mowat, L. Wickramaratne, M. Teixeira, Geoprobe Drilling.

A deepwater exploration drilling system is being designed to deploy a slim, one-trip riser from a mono-hull vessel using drilled in conductor. The subsea shut-off system must weigh less than 30 tons. Accumulators become inefficient with increasing water depth as their size and weight needed to store a given quantity of energy increases.

The need for a rapid and reliable method of disconnecting the riser lead to the development and testing of a battery-powered shear ram system. Batteries also power the alternative Annular Cutting Tool (ACT) pipe severance method, based on thermal torch technology. This provides an even radial cut for full-bore re-entry compared with the belled over profile of sheared pipe.

A prototype subsea pod was built consisting of military-spec batteries connected to an electric motor and variable displacement hydraulic pump. By the direct supply of hydraulic fluid to and from the shear rams, high-pressure SPM valves are removed from the control system. The resulting high power-to-weight ratio enabled the pod weight to be kept below 0.5 tons. Successful and repeated shear tests were conducted on concentric 7 5/8-in. and 5 1/2-in. casings with a small battery set without recharge. The results will be presented.

IADC/SPE 112704

Evaluating the True Cost of Losing a Bottomhole Assembly. E.M. Tollefsen, A.L. Weber, D. Crowell, Z. Nagy, Schlumberger.

Losing a bottomhole assembly (BHA) is one of the most costly unplanned drilling events that can occur for an operator. Time spent fishing for the lost assembly, the rig time wasted waiting on the mobilization of countless amounts of equipment and people, and the additional costs of whipstocks, cement and directional tools increase the cost of a well almost exponentially. The new well plan may also lead to any number of problems with tortuosity and torque and drag farther down the wellbore. Typically, these expenses are invoiced individually, and often this cumulative cost to reach the same true vertical depth as the stuck assembly is not readily apparent.

Often, one of the largest invoices the operator receives during a stuck BHA event is the replacement cost of the LWD technology. This large invoice amount does much to disguise the other costs of sidetracking, leading many operators to weigh the risk of losing the technology far above the benefits of running it in the hole.

As well difficulty increases and the risk of a stuck pipe event grows, operators become less likely to run LWD tools in the hole. Unfortunately, this mentality creates a paradox, because many of the

new LWD technologies, including annular pressure while drilling, formation pressure while drilling, and sonic and seismic while drilling, are capable of significantly reducing the risk of a lost in hole (LIH) event. Also, if this technology is lost, the additional information to analyze and replan the new wellbore can prove to be invaluable.

This paper will analyze data and case studies in the Gulf of Mexico to perform a risk analysis that includes the true cost of sidetracking a well, with and without the appropriate LWD technology in the drillstring.

Technical Session: Casing While Drilling

IADC/SPE 111806

Successful Application of Casing-While-Drilling Technology in a Canadian Arctic Permafrost Application. H. Vrieling, BP; J.S. Bradford, Chevron; L. Basarab, Tesco Corporation; C.C. Ubaru, Hughes Christensen.

The JV operator was looking for a combination of technologies to optimize drilling in Canada's Mackenzie Delta region. The area is characterized by a permafrost section up to 2,000 ft thick. This shallow permafrost section is dominated by unconsolidated silt with fresh water ice ranging from 60% volume to pure ice layers. Historically, mechanical heat input has melted the frozen layer resulting in increased hydrates/shallow gas risks, extreme hole enlargement/cleaning problems, rig support issues, wellbore instability, stuck pipe and hydraulic isolation issues.

Optimizing drilling operations through the shallow section is critical to maximize the number of wells that can be drilled with the available rigs in this limited access area. To move the rigs requires approximately 3 ft of ice cover, significantly limiting the operating season and increasing the need for rig efficiency and reduction of NPT. The industry has universally endorsed the importance of mud cooling through the shallow permafrost and the underlying hydrate-bearing formations to avoid borehole instability and control hydrate dissolution. However, the industry has struggled to maintain sufficiently cold mud at the high pump/power rates required to effectively drill/clean the larger surface holes.

To solve the challenges, the operator utilized a casing while drilling PDC bit (CwD) combined with a mud-chilling technology and a variety of controlled drilling parameters. The CwD allowed the operator to drill and set casing through the problematic zones in one operation with relatively low flow rates to avoid hole enlargement. The lower flow rates also enabled the use of smaller/lighter rig equipment.

IADC/SPE 112544

Annular Pressure Loss Predictions for Various Stand-off Devices. D. Yao, University of Houston G. Robello, Halliburton.

During drilling and cementing operations, many stand-off devices, such as centralizers, stabilizers, reamers, turbulators and friction reduction devices, are widely used. Some of these devices are designed to enhance the displacement efficiency during cementing operations, to increase hole-cleaning efficiency, or to reduce torque and drag. Few studies have explored the pressure losses arising from these attached devices in the drillstring or casing string, and are assumed to be negligible. The geometrical designs of these devices are relatively irregular and complicated, which is one of the major difficulties for pressure-loss calculations.

This study examines the effect of the various geo-

metrical parameters of the commonly used devices, flow rate and rheological properties on the annular pressure loss using computational fluid dynamics (CFD). This paper presents the results of the study of the alteration and effects of various rheology models on the flow profile and annular pressure losses.

IADC/SPE 112545

Casing Drilling in the San Juan Basin to Eliminate Lost Returns in a Depleted Coal Formation. S.D. Robinson T.M. Bealesio, R.S. Shafer, ConocoPhillips.

A casing drilling pilot program was conducted in the San Juan Basin to determine if lost returns could be eliminated in a depleted coal formation. Five wells were identified as having high potential for lost returns while drilling the coal. Four wells were actually drilled with casing. Three wells drilled through the coal and had losses that were eliminated with casing drilling. One well had a bit failure and did not make it into the coal. One other well was eliminated from the program after a fatigue failure occurred.

The pilot program was completed with significant learnings. A non-retrievable casing drilling system successfully drilled to the intermediate casing point without a trip. The bit design was changed significantly and resulted in about 100% improvement in ROP with instantaneous ROPs similar to traditional PDC bits. The initial casing design was modified to decrease vibration and eliminate fatigue after a failure was experienced. DV tools and float collars were used with success. The bit used to drill with casing was drilled up with an air hammer bit. Air compressors were used to help improve ROP and to reduce ECDs. Losses were healed in the coal and foam cement was circulated to surface.

IADC/SPE 112560

A Case History of Casing Directional Drilling in the Norwegian Sector of the North Sea. K.A. Bourassa, T. Husby, R.D. Watts, ConocoPhillips; D. Oveson, T.M. Warren, Tesco Corporation; H. Bjoerneli, W.G. Lesso, F. Sunde, Schlumberger.

In January 2007, ConocoPhillips Skandinavia AS completed what is believed to be the first well to be directionally drilled with casing in conjunction with wireline retrievable bottomhole assemblies (BHAs) from an offshore installation. Based on ConocoPhillips experience on land in reducing drilling days on predominately vertical wells in South Texas, it was desired to determine if the same benefit could be realized in the offshore environment; where directional drilling is required. A candidate development well was identified in Norway on the ConocoPhillips-operated Eldfisk Bravo platform that could benefit from advantages seen with Casing Drilling. Once the first of two land-based tests was completed, which confirmed the ability of conducting casing directional drilling, detailed planning began.

The planned well had a complex 3D wellpath and a planned inclination up to 60°. Casing functioned as the drillstring, with all running and retrievals of the BHAs done on wireline with a purpose-built traction winch system rated to a working load of 40,000 lbs. Two production casing strings, 10 3/4 in. and 7 7/8 in., were directionally drilled through the overburden section on a development well. Once the 7 7/8-in. production casing was cemented, the casing string was converted to a production liner with a unique expandable liner hanger and the upper section of 7 7/8 in. was retrieved. In all, 10,968 ft MD (3,343 m) of the 13,600 ft MD (4,145 m) well was directionally drilled with casing.

This paper will summarize the planning activities, highlight additional "new to field" technologies used on the well, describe the required platform and rig modifications, summarize the actual operation then present results and conclusions.

IADC/SPE 112561

Development, Testing and Field Deployment of a Hydraulically Expanded Solid Liner Hanger in a Casing Directionally Drilled Well in Norway. K.A. Bourassa, T. Husby, R.D. Watts, ConocoPhillips; P.R. Hazel, C. Nussbaum, P. Wood, Read Well Services.

When ConocoPhillips Skandinavia AS decided to conduct casing directional drilling (CDD) operations from a platform in the Norwegian Sector of the North Sea, the well design required that the drilled in 7 7/8-in. production casing string be converted into a liner prior to completing the well. There was a challenge in identifying a liner hanger system that would be suitable for CDD operations; that did not require a running tool; would maintain a full internal diameter (ID) for running and retrieving BHAs and would act as a barrier against gas migration over the service life of the well.

Expandable technology was identified as a potential solution. A basis of design was established, and testing began. The result after 18 month was a successful field deployment of a 7 7/8-in. liner hanger that was drilled in from surface; successfully expanded into 10 3/4-in. casing; had a load capability of over 440,000 lbs (200 metric tons) and a 5,000 psi (345 bar) gas-tight seal qualified to ISO 14310:V0.

This paper will describe the development, testing and actual deployment that took place between December 2006 and January 2007.

IADC/SPE 112608

Installing 56 Surface Casing Strings in 40 Well Slots Successfully in Bohai Bay, China. F. Fu, S.C. Actis, K.J. Strachan, ConocoPhillips.

ConocoPhillips is developing the Peng Lai field in Bohai Bay offshore China with six wellhead platforms (WHP) in 28 m (92 ft) of water. Phase I entailed one 24-slot WHP and a leased FPSO that has been in production since 2002. Phase II will have five 40 slot WHPBs and a permanent FPSO. The 24 inner slots of four of the Phase II WHPBs will have 20-in. drive pipe conductors, and the 13 3/8-in. surface casing will be installed by drilling with casing. The 16 outer slots, 8 on the north row and 8 on the south row, will have 36-in. drive pipe conductors and provide dual bore 13 3/8-in. surface casing strings in each slot that are set at a slight angle to facilitate subsequent directional drilling.

The 56 wells slots drilled from a 40-slot WHP reduces the size and cost of the platform while roviding additional wells to meet the reservoir development plan.

The 13 3/8-in. surface casing strings, using both the drill with casing and dual bore methods, are installed during batch setting programs by using a jackup. The jackup continues to pre-drill wells until the topside installation begins and the jackup moves to the next platform. The drilling program on the last WHP, to be installed in 2009, will be conducted exclusively from a platform rig, including the 13 3/8-in. drill with casing program in all 40 slots.

This paper will describe the well construction program as part of the field development plan, the installation procedure and results of the surface casing installation programs and the drilling savings realized as a result of using drill with casing and dual bore conductor technologies.

IADC/SPE 112776

Novel Stabilizers for Casing Drilling Simplify BHA, Handling, and Cost. D.C. Limbert, ConocoPhillips; S. Langford, Grant Prideco; J.H. Gammage, Wearsox.

A novel technique for building stabilizers and wear

bands directly onto casing for drilling is replacing multiple machined integral stabilizers. This is achieved with spray metal technology, and the resulting blades, ribs and bands are as equally wear-resistant as steel. Multiple stabilizers can be built onto a single joint of Range 3 casing to create the desired BHA.

The spray metal process is commonly used in other industries for corrosion and erosion protection using relatively thin layers. The novelty of this new process is that the wear metal can be built up to thicknesses of $\frac{3}{4}$ in. (19 mm) and in any desired shape. This is a new application of the process in casing for drilling because it has also proved successful recently in protecting drill pipe tube from wear in extended-reach wells and in highly abrasive formations.

Field test results indicate that the material is sufficiently robust to withstand normal downhole forces and the associated rotational and longitudinal abrasion. The casing was deliberately tripped after drilling to TD to inspect stabilizer integrity and to measure wear. Further laboratory work is being undertaken to compare the material's wear and frictional characteristics with more common materials.

Technical Session: Fluids Technology II

IADC/SPE 112620

How Effective Is Current Solids Control Equipment for Drilling Fluids Weighted With Micron Sized Weight Material? J. Massam, S. Stocks, D. Oakley, C. Bremner, M-I Swaco.

Centrifuges and shakers are the first defence when managing a drilling fluid against wellbore cuttings and solids contamination. The buildup of drill solids in a fluid can have a detrimental effect on its performance and properties. Much of the solids control equipment in the field was designed with conventional API grade weighted fluids in mind, but the increasing use of drilling fluids in the field weighted with micron-sized particles has presented a challenge in the use of existing solids control technologies to achieve effective solids removal.

With a decanting centrifuge, the particle size and density of API grade barite is such that the centrifugal force tends to remove much of it from the fluid together with the undesired solids. Similarly, the wire mesh size for shaker screens is selected to be effective in removing the cuttings, but consequently the coarser fraction of the weight material is removed. A significant reduction in weight material particle size has the potential to demonstrate a different behaviour. This paper will present data obtained from both the field and from specifically designed yard tests conducted on micronized weighted drilling fluids.

The data discusses the solids removal efficiency using different centrifuge designs as well as shaker screen performance, and demonstrates how these can be optimized for the preferential removal of undesirable contaminants and minimize removal of the desired weight material. The operating parameters of the centrifuge have been defined to provide the optimum solids removal efficiency.

IADC/SPE 112657

Use of New Hydrostatic Packer Concept to Manage Lost Returns, Well Control and Cement Placement in Field Operations. F.E. Dupriest, ExxonMobil.

Hydrostatic Packers have become an essential tool in the operator's lost returns response practices. They consist of a column of light fluid introduced

into the annulus or drill string to cause the total hydrostatic head to be underbalanced to the stress in the loss zone. This causes the hole to stand full and allows accurate placement of cement, lost returns treatments or other fluids in situations where they would otherwise be overdisplaced. Although they are not a physical device, they are referred to as a packer because they effectively serve many of the same functions as retainers and squeeze tools.

Despite the current maturity of field applications, the concept has not been adopted widely by the industry. Hydrostatic packer design and use requires training, an understanding of the role of fracture closure stress during lost returns, and the development of specific field practices to mitigate potential risks. This paper discusses these points, as well as specific operational issues that must be considered in certain unique situations.

IADC/SPE 112727

Treatment of Nonaqueous-Fluid-Contaminated Drill Cuttings — Raising Environmental and Safety Standards. A.J. Kirkness, D. Garrick, TWMA.

Drilled cuttings and other hydrocarbon-contaminated wastes generated in offshore drilling operations have been processed onshore for many years. The transporting ("skip & ship") of large tonnages of cuttings from offshore installations to shore-based processing facilities carries considerable environmental and safety implications. The concept of processing these contaminated cuttings offshore and the recycling of both the recovered oil and water back into the drilling fluid provides a unique solution.

Since 2002, the application of this technology has gained wider use and acceptance, allowing for a thorough evaluation of its application in resolving many of the more intransigent problems associated with drilling waste management in offshore operations. This paper reviews the work completed to date and how it might best be applied in the future.

IADC/SPE 112687

Automatic Measurement of Drilling Fluid and Drill Cuttings Properties. A. Saasen, T. Omeland, StatoilHydro; S. Ekrene, J. Breviere, E. Villard, Geoservices; N. Kaageson Loe, A. Tehrani, J. Cameron, M. Freeman, F. Growcock, A. Patrick, T. Stock, M-I Swaco; T. Jorgensen, F. Reinholt, N. Scholz, AnaTec; H.E. Amundsen, A. Steele, EPX; G. Meeten, Schlumberger.

In order to remotely control the drilling process, it is necessary to measure several drilling fluid parameters automatically. This will increase objectivity of the measurements as well as make it possible to immediately react to changes. The current paper describes the design for an integrated tool combination and the result a full-size yard test of such a combined set of tools for measuring drilling fluid parameters and formation properties automatically. Some of the automatic tools have been tested on rig site operations. Results from these individual tests will also be presented.

IADC/SPE 112602

Mitigating Risks From Waste Subsurface Injection Through Accurate Downhole Pressure Measurement, Analysis and Fracture Monitoring. T. Shokanov, F.E. Fragachan, M I Swaco; S.B. Feyereisen, BP.

An enhanced environmental awareness and increased requirements for effective drilling and production waste management forced many operators to search and implement the most environmentally friendly and cost-effective solutions for waste disposal. Subsurface drilling and production waste

injection has been a proven as an environmentally sound alternative. However, any subsurface injection operation must be accompanied by subsurface modeling and continuous pressure monitoring to ensure subsurface waste containment and avoid injectivity risks.

This paper describes the benefits and value generated from the real-time downhole pressure measurements for the first time recorded during subsurface waste injection operations. The pressure measurements were utilized for accurate disposal fracture characterization. Injection pressure monitoring and detailed analysis of downhole pressure response during injection and decline periods provided quality waste management assurance. The authors describe the results of injection monitoring and in depth pressure analysis for injection assurance in a dedicated waste injection well, located offshore in the southern Caspian Sea.

IADC/SPE 112529

Reducing Risk by Using a Unique Oil-Based Drilling Fluid in an Offshore Casing Directional Drilling Operation. R.W. James, ConocoPhillips; O. Prebensen, Ø. Randeberg, M I Swaco.

The conventional drilling approach of employing a drill string and drill bit and eventually running a casing string includes several tripping operations and leaves the wellbore open for an extended period of time. As an alternative, drilling with casing, where the drill bit is attached to the casing, eliminates additional tripping. This type of application reduces the number of trips needed to complete a section. As the diameter of a casing is larger than a drill string, this method generally increases the equivalent circulating density (ECD) as pressure losses increase because of a reduction in the annular gap between open hole and casing string. Casing directional drilling applications provide a much narrower drilling window with regards to restrictions in the annulus, thus increasing the chances of reaching fracture pressure. To negate the increase in ECD, the rheological profile of the drilling fluid must be designed accordingly.

This paper discusses an oil-based drilling fluid system weighted with treated micron-sized barite (TMSB) slurries that has been developed and successfully used in the field. The drilling fluid system provides low viscosity and a flat rheology; reduced torque values, superior sag stability, thus delivering a fluid with low ECD contribution, pressure peaks and very effective hydraulics performance.

IADC/SPE 112604

Experimental Study and Modeling of Yield Power Law Fluid Flow in Annuli with Drillpipe Rotation. R.M. Ahmed, S.Z. Miska, University of Tulsa.

Helical flow of non-Newtonian fluids in concentric and eccentric annuli is of great interest in oil/gas well drilling. Experimental results and field measurements demonstrated that frictional pressure loss in the annulus can be affected substantially by the rotation of the drillpipe. Previous studies indicated that the influence of pipe rotation on annular friction pressure loss is affected by fluid properties, flow regime, annular diameter ratio and eccentricity.

This article presents results of in depth experimental and theoretical investigations conducted on the flow of yield power law (Herschel Buckley) fluids in concentric and eccentric annuli with pipe rotation. The aim of this study is to develop a reliable hydraulic model that accounts for the effect of pipe rotation in annular pressure loss calculations. ☐