Deepwater Exploration and Production

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Even in today's changing times, the challenges of deep water continue to demand new and innovative technologies. Explorers are finding new fields hidden tens of thousands of feet below the mudline, reaching depths that cannot be completed currently. To produce from these depths, companies are developing completion equipment rated to high pressures both in absolute and in differential terms. Successful qualification of new high-yield metal alloys is a key enabler for delivery of high-pressure/high-temperature completion-equipment solutions; specifically in the development of a 20,000-psi-rated surface-controlled subsurface safety valve, 15,000-psi-differential-rated completion equipment, and 30,000-psi-rated downhole-test-tool equipment. The current mechanical-property limits for high-yield metal-alloy materials must be extended with material solutions that provide robust corrosion performance.

Past experiences by many operators have led to a rigorous assurance process to ensure that new equipment will work and work the first time. Equipment statement of requirements, detailed design reviews along with comprehensive qualification plans, system-integration tests, and, potentially, field trials are part of the overall equipment-integrity assurance.

As we continue to explore in deep water, new horizons at depths never before completed demand new ideas and new technologies to enable development. As professionals working in the oil industry, we need to continue working together to find new ways to develop these deeper high-pressure reservoirs and then to develop the equipment to produce them. We need to keep that "can-do" attitude.

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Deepwater Exploration and Production additional reading available at the SPE eLibrary: www.spe.org

SPE 113727 *• "Optimizing Wireline-Gun-System Design and Perforating Performance for Very Late Changes in a Gulf of Mexico HP/HT Deepwater Well" by L. Sabbagh, SPE, Schlumberger, et al.*

Additional reading available at OnePetro: www.onepetro.org

OTC 20022 *• "Geohazard Assessment in a Deepwater Subsea Development—A Contractor's Perspective" by Roberto Bruschi, Saipem Energy Services, et al.*

OTC 20087 *• "Early Testing—Jabuti Extended Well Test" by J.R.C. Melo, Petrobras, et al.*

Testing Titanium-Alloy Tubing for HP/HT Applications

Flow streams from high-pressure/high-temperature (HP/HT) wells usually contain H_2S, CO_2, and chlorides. Such wells with temperatures greater than 350°F require corrosion-resistant-alloy (CRA) tubing/casing. Titanium alloys can provide for an alternative. A testing program was developed to qualify Ti-6246 alloy for use in Chevron's sour-gas oil fields.

Introduction

The test program's objective was to qualify a 135-ksi Ti-6246 production-tubing alloy. The alloy would be suitable for production tubing as an alternative to nickel-based alloys and superduplex stainless steels, depending upon the application. This alloy, Ti-6Al-2Sn-4Zr-6Mo, was selected for qualification testing. Adding molybdenum gives the alloy exceptional corrosion resistance to chlorides and H_2S. The two-phase structure allows the alloy to be heat treated to optimize desired properties.

Environmental Material Test

This qualification program was designed to evaluate environmental-cracking susceptibility (e.g., stress-corrosion cracking and sulfide stress cracking) and overall corrosion performance of alloy tubulars exposed to several simulated oilfield-service environments including packer fluids, simulated production fluids, methanol, and mineral acid. The production environment was formulated to show suitability for most HP/HT wells. C-ring, slow-strain-rate testing (SSRT), and fracture toughness were methods used in this test program. Crevice-corrosion coupons and galvanic couples also were used in some tests.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 115708, "Titanium-Alloy Tubing for HP/HT Applications," by ***Manuel Gonzalez,*** *SPE,* ***Krystian Maskos,*** *and* ***Robert Hargrave,*** *SPE, Chevron Energy Technology Company;* ***John Kuberry,*** *SPE, and* ***Doyle Reeves,*** *Hunting International;* ***Jim Grauman,*** *Titanium Metals Corporation;* ***Jim Skogsberg,*** *Consultant; and* ***Syed Ali,*** *SPE, Schlumberger, prepared for the 2008 SPE Annual Technical Conference and Exhibition, Denver, 21–24 September. The paper has not been peer reviewed.*

Packer-Fluid Tests. Saturated 15-lbm/gal noninhibited $CaBr_2$ brine at 500°F was used to test C-rings stressed at 90% average-yield strength (AYS), crevice specimens, and corrosion coupons. Test duration was 90 days. All C-rings passed with no cracking, pitting, or crevice corrosion. Corrosion did occur on the carbon steel.

Saturated noninhibited 19-lbm/gal $ZnBr_2$ brine at 500°F was used to test C-rings stressed at 90% AYS, crevice specimens, and corrosion coupons. Testing duration was 90 days. All C-rings passed with no cracking, pitting, or crevice corrosion. Carbon-steel wastage was very significant compared with specimens exposed to $CaBr_2$ brine.

Production-Environment Tests. ***C-Ring Tests in Production-Environment A.*** C-rings stressed to 90% AYS were tested in Production-Environment A (without elemental sulfur) for 5 months. Production-Environment A was at 500°F with 1,500-psia H_2S, 425-psia CO_2, and 25% NaCl brine (150,000 ppm Cl). All C-rings in the test passed the Production-Environment-A test with no cracking, pitting, or crevice corrosion.

Some titanium alloys are sensitive to hydrogen embrittlement, and because carbon steel corrodes, there is the possibility of hydrogen charging of the titanium alloy. The charging in these tests was not significant, and the C-rings did not crack. Subsequent environmental tests measured very low hydrogen levels in the alloy after galvanic coupling with carbon steel.

C-Ring Tests in Production-Environment B. Production-Environment B included elemental sulfur. These tests were conducted for 90 days at 400°F. Production-Environment B included 1,500-psia H_2S, 425-psia CO_2, 25 wt% NaCl brine (150,000 ppm Cl), and 1 g/L of elemental sulfur. All C-ring specimens passed with no cracking, pitting, or crevice corrosion. The average corrosion rate was low, at approximately 0.1 mpy.

Additional C-ring specimens stressed to 100% AYS were coupled to carbon steel and tested in Production-Environment B. All C-rings passed with no cracking. There was significant corrosion of the carbon-steel coupling material.

SSRT in Production-Environment B. Notched SSRT specimens were pulled to failure at ambient temperature and pressure in air after a 90-day exposure to Production-Environment B. The notched SSRT specimens had no applied tensile load during the 90-day exposure. The results indicated a drop in the average maximum tensile load in the environmentally exposed specimens of approximately 5% compared with baseline specimens.

Hydrogen Measurements After Production-Environment-B Exposure. The amount of hydrogen in the titanium alloy was measured after 90-day exposure to Production-Environment B. C-rings were tested after exposure to the production environment, both with and without galvanic coupling to carbon steel. A nonexposed sample (baseline) was also tested. Results indicated no significant hydrogen absorption during the 90-day exposure. Thus, the hydrogen content even after exposure was below the allowable limit.

Methanol SSRT. Notched-SSRT in methanol with 1% H_2O was performed at room temperature. The results indicated that this alloy material is susceptible to environmental cracking in this environment. Notched SSRT in methanol with 5% H_2O addition also was performed. No evidence of environmental cracking was observed on the test specimens in the presence of 5% H_2O.

C-ring testing in methanol with 5% H_2O at room temperature confirmed the SSRT results. The C-rings were stressed to 90% AYS. C-ring exposure to methanol lasted 30 days, with an initial water content of 5.01%. No cracking was observed under stereoscopic examination of the C-rings.

Corrosion Tests in Inhibited Hydrochloric Acid. Corrosion tests were used to measure the resistance of this alloy to inhibited hydrochloric acid (HCl). The test conditions included both 10 and 15% HCl aerated solution, at 250°F, with 12% H_2S. Sodium molybdate (60 g/L) was used to inhibit the corrosion caused by HCl. Acid exposure times of 6, 9, and 16 hours were used for the tests.

Test results for the 6- and 9-hour exposures showed wall-loss values within industry standards. The 16-hour exposure had weight-loss values greater than the standard for acceptable corrosion losses. No pitting or localized corrosion was observed on any of the test coupons. Acid stimulations with less than 9 hours of pumping time (inhibited 15% HCl stage) should present no problems for the titanium tubing. Pumping a water stage before pumping the acid will help cool the tubing and further reduce the effects of surface-area wall loss.

Fracture-Toughness Tests

Fracture toughness is the resistance of a material to fracture propagation from a pre-existing crack. Toughness of all titanium alloys measured by Charpy impact tests is poor because titanium alloys generally exhibit low toughness under high strain rates. Titanium alloys demonstrate reasonably good fracture toughness under low strain rates.

Fracture-toughness tests were performed on two sizes of titanium-alloy seamless pipe, 4^1/2-in. and 9^5/8-in. outside diameter. Two specimen geometries were used: arc-tension and single-edge notched bend (SENB). The arc-tension coupon combined bending and axial loading because of the geometry. The SENB geometry experiences only a bending stress, with the maximum bending stress in the midspan at the single loading point. The overall boundary condition is defined as a three-point bend configuration with two outer loading points and one inner loading point (at the point of maximum stress). The precrack is at the midspan and, thus, at the region of highest stress. It is important to note that both of these geometries have well-defined stress-intensity solutions and have been used for some time in fracture mechanics. See Table 1 in the full-length paper for details.

Passivation Test in NaCl Brine

A test was designed to determine the repassivation tendency of this titanium alloy in the absence of oxygen. Electrochemical testing of the titanium alloy was performed after mechanical scratching in an oxygen-free environment. The results suggested that this alloy will repassivate almost instantaneously after scratching in an oxygen-free simulated environment, such as downhole production environments.

Sand Erosion and Erosion/Corrosion Tests

A series of tests was conducted to examine sand erosion and erosion/corrosion resistance. Sand erosion and CO_2 corrosion can be critical for alloy-tubing life, particularly at the high velocities associated with large-bore gas wells.

A three-phase experimental study was undertaken. In Phase 1, erosion resistance of the titanium alloy was investigated by use of direct-impact testing with sand entrained in an air jet impacting the alloy specimens. In Phase-2 studies, specimens were placed in a 2-in. standard elbow. The length/diameter ratio upstream of the elbow was 150, to promote fully developed flow near the test section. Solid-particle-erosion testing was conducted with air and air/water multiphase (annular) flow. In Phase 3, both pure erosion testing and erosion/corrosion tests involving CO_2 gas were performed. The pure erosion testing was conducted with nitrogen as well as with CO_2. Test results were compared with previous results that are reported in the literature for corrosion-resistant alloys and other materials of interest to oil and gas companies.

Mechanical Testing

Collapse tests were performed on titanium-alloy seamless pipe to correlate actual with predicted results. Samples were industry-accepted length of eight diameters. All testing was at room temperature. The test results, presented in Fig. 3 of the full-length paper, indicate that the American Petroleum Institute elastic-collapse formula represents a close approximation of actual collapse values for this titanium alloy.

Connection Tests

Qualification of a proprietary 4^1/2-in. connection for use in the most-severe critical-service applications was completed for all combined-load tests without leaking or damage to the connection. Testing to date verified structural integrity and leak resistance of the connections when subjected to loads up to 200-kip tension (i.e., a 26,700-ft-long string), 180-kip compression, 14,000-psi internal pressure, and 8,100-psi collapse pressure.

Conclusions

This test program showed that titanium-alloy pipe is comparable to nickel-based alloys traditionally used for production tubing in corrosive and highly sour wells. The titanium alloy shows excellent resistance to environmental-stress cracking in production, workover, and completion environments that may occur in severe HP/HT and deepwater fields. Burst strength and connection performance also were documented. The test program pointed out limitations of the titanium alloy that can be resolved with appropriate project planning, tubing design, and field-operations practices that take into account the unique properties of the metal. As with any CRA-material selection, project-specific testing should be considered to define material performance with respect to the environments and stresses assumed for the completion. After redesigning a 4^1/2-in. tubing connection to take into account titanium's unique properties, a premium metal-to-metal seal can perform well under the HP/HT conditions in Chevron's sour-service fields. **JPT**

Pull Your BOP Stack—Or Not? Systematic Method to Making This Multimillion Dollar Decision

Pulling the blowout-preventer (BOP) stack, particularly in deep water, is costly. While in most cases this action is proper, circumstances arise when the stack pull could be avoided. Case studies are presented in which planned stack pulls were circumvented or could have been. A systematic protocol can be developed before starting a well to define the decision-making process for stack pulls.

Introduction

Current deepwater-rig downtime costs approach USD 1,000,000/D. Pulling a BOP stack, particularly in deep water, is financially significant. This action is necessary most of the time. However, on occasions when the stack pull could be avoided, all parties to this action rightfully question how to take advantage of the unfortunate learning situation. Avoidable stack pulls occur for a variety of reasons, including:

- Inadequate information about the situation or equipment
- Inadequate staff training
- Unclear understanding of regulatory requirements
- Unclear understanding of company requirements
- Lack of access to experts who could assist in the decision

The full-length paper details a systematic protocol to use before starting a well or during the drilling, if necessary, to help define the decision-making process for stack pulls for a specific program. Once a problem develops, the root cause should be identified, if possible, and necessary steps taken to analyze the situation and decide if drilling can continue safely. Often, this part of the process requires the advice and experience of one or more experienced drilling experts from within or outside the parties directly involved in the drilling operation.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 119762, "Pull Your BOP Stack—Or Not? A Systematic Method to Making This Multimillion-Dollar Decision," by ***Jeff Sattler,*** *SPE, WEST Engineering Services, prepared for the 2009 SPE/IADC Drilling Conference and Exhibition, Amsterdam, 17–19 March. The paper has not been peer reviewed.*

Predrilling Planning

To help ensure a good decision when an abnormal BOP event occurs, preparations should be made before drilling starts. While several items presented here require time to investigate or review, often this process is not engaged because much of the information is considered to be intuitive. However, after drilling begins and because time is expensive (up to USD 700/min or more), the time required to analyze a situation fully is sometimes not allocated. Predrilling planning, as shown in Fig. 1 of the full-length paper, should include the following items.

Assess Staff Training. Review staff experience and training to determine if additional training before drilling could reduce the risk of downtime. For example, does the subsea engineer need to be educated on the functionality of a revised circuit or control component? Would the subsea engineer benefit from a refresher on the latest variable-bore-ram capabilities and limitations?

List Persons To Contact for Expert Advice. Gather the names and contact information of knowledgeable people and organizations inside and/or outside the company to contact in the event of a potential stack-pull decision. This list might include the method for contacting these people from a remote drilling location at any time of the day. These people should be chosen carefully because they may be key to making the correct decision.

Review Equipment and Configuration. Determine what BOP equipment is used with the rig and its configuration. Determine which spare parts and supplies may be needed, especially those that could reduce downtime after drilling begins (e.g., having the proper remotely-operated-vehicle (ROV) tool or connection to activate a BOP function). Ensure that the ROV can execute the required tasks by testing before need.

Review Regulations for Well Control, Safety, and Environmental Concerns.

Local. Government regulations will supersede all other policies and standards. Some areas of the world have significant government regulation, while others have little or none.

Company. Company policies include those of both the operator and the drilling contractor.

Other. Decide which other regulations, policies, and industry standards (e.g., US Mineral Management Service and International Association of Drilling Contractors), if any, will be used.

Define Minimum Requirements for the Lower-Marine-Riser Package (LMRP)/BOP-Stack Functions. Before drilling starts, use the gathered information to determine and record the minimum requirements for equipment and functions for the LMRP/BOP. This list will help ensure the correct choice when the time comes to decide whether to pull the LMRP/BOP. To help with this task, complete the following lists.

- Equipment and functions required to meet local regulations, company policy, or industry standards

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

- Additional equipment and functions required for minimum well control
- Additional equipment and functions required for an emergency-disconnect sequence

While many of these steps are very basic, some of these issues have been debated in the middle of a drilling program. Requirements that might be considered as basic may not be in complete agreement with what is in the mind of all people involved with the operation. Once this process is defined, the effort for a given well could be relatively minor; communication of these parameters then becomes part of the operator's standards manual.

It is important to consider if functions can be broken down to lower-level functionalities. It is helpful to define the criticality of lower-level functions.

You Have a BOP Problem—What Do You Do Now?

A drilling program can have any combination of problems, circumstances, and potential solutions at a given time. Therefore, it is almost impossible to develop a comprehensive decision matrix for answering the question of whether to pull the BOP. Fig. 2 in the full-length paper shows a general decision tree that can be followed to assist the stack-pull decision for most LMRP/BOP problems. Different cases may require different decision paths. Two of four case studies from the full-length paper are highlighted.

Case Study 1. A rig in western Africa encountered a control-system leak that led to suggesting that retrieval of the LMRP was necessary. However, when the shore-based drilling manager was informed of this recommendation, he opted for a second opinion from another experienced source. A teleconference was organized to allow the drilling manager, his staff, and a control-system expert to discuss the problem at hand.

After job files and schematic drawings were gathered, the data were reviewed with rig personnel. The ensuing discussion identified the problem as a leak in the BOP-control system between the conduit-valve manifold and one of the pods. It was decided to use the tight pod for primary control and reserve the leaking pod for backup. If the primary (tight) pod began to deteriorate, the backup pod would be used to make the well safe and the LMRP would be retrieved for repair. This operating decision allowed the rig to maintain control redundancy while minimizing the possibility of causing the leak rate to increase.

This plan allowed drilling to continue safely, and the repair was scheduled for routine between-well maintenance instead of suffering unnecessary downtime. The driller was able to avoid pulling the LMRP, saving approximately USD 1,500,000. Most importantly, the driller was able to do this knowing that the environment and the safety of people were not at risk.

Case Study 2. Several simultaneous leaks and failures in the LMRP and BOP stack were experienced while conducting function testing of a stack operating in western Africa. While most of the issues were minor by themselves, together they presented concern whether to continue operating, to pull the LMRP, or to pull the entire BOP stack. Shore-based assistance was used to help with the decision. Over the next few days, several phone conferences were organized to allow the drilling manager, his staff, and the shore-based experts to discuss the issues and identify the root causes more clearly.

As a result of the discussions, identified problems included the following.

- Leak on surge/stripping accumulator-bottle hose on the upper annular system, which disabled the upper-annular-system operation on both pods
- Leak on manually preset 5,000- to 3,000-psi supply regulator to all pod functions; subsequently reduced by tightening nuts with an ROV
- Leak on mud-boost-valve open function from one pod
- Leak on lower-annular-system open function on function hose or male receptacle

Review of the various problems led to the conclusion that with the regulator leak under control, the loss of upper-annular function was the most significant problem, but that the minimum required annular function was still available with a working lower-annular system. This made reliable operation of the lower-annular system a critical requirement for minimum well control, so the leak in the lower-annular system was scrutinized. The annular system's closing function worked satisfactorily; therefore, the annular system could still provide well control. Although the annular system leaked hydraulic fluid while opening pressure was applied, the leak stopped when the valve was in the block. Opening an annular system is a transient operation. Annular-system design results in this preventer remaining open after being opened without maintaining open hydraulic pressure. Therefore, open hydraulic pressure need not be applied for a prolonged period of time, minimizing the possibility that the leak would get worse. In a worst-case scenario, if the annular-system open function lost all pressure and the annular system did not open by itself (because of loss of memory in the rubber), then the ROV could be used to pressurize the annular open function and open the preventer. The driller chose to leave the open-function valve in block until it was needed.

As a result of definitively identifying the control-system problems, as well as clearly defining and agreeing upon minimum stack functionality, a pulling event was averted and drilling continued.

Conclusions

Taking time to develop and gain consensus on a stack-pulling philosophy is an excellent practice before beginning a drilling program. This procedure should include an analysis of the needs of the program, a definition of minimum requirements for LMRP/BOP functions, and a preapproved list of various subject-matter experts who can be contacted for additional expertise in the event they are needed. The extra expertise can come from experienced and knowledgeable persons within the company and/or from third-party experts.

Once a problem is encountered, invest time to diagnose the root cause properly before acting. When the root cause is identified as well as possible, analyze the situation and then decide if the problem truly violates the minimum requirements or if there is a way to meet those requirements and continue operating safely. Often, contacting shore-based personnel will result in alternatives not considered previously. These alternatives might be a variety of sources including the opportunity to brainstorm with others who may have different experiences and be less fatigued. The few hours spent on additional diagnoses over many stack-pull situations can be repaid easily with a single event of avoidance. **JPT**

Design Challenges for Wax in a Fast-Track Deepwater Project

Flow-assurance threats, such as hydrates, waxes, and asphaltenes, can be identified and controlled if oil and gas production and transportation systems are designed accordingly and proper operating procedures are implemented. Therefore, prevention of wax deposition is key for good subsea deepwater-system design. Wax deposition can form a blockage and impede flow, causing weeks of lost production and operating difficulties.

Introduction

Flow assurance in subsea systems is an issue in the design of deepwater-field developments. Flow-assurance efforts focus on preventing solid deposits from blocking or restricting the rate of flow from the well. The principal solids of concern are wax and hydrates. For a given reservoir fluid, these solids precipitate at certain combinations of pressure and temperature. Precipitated solids often are carried downstream, slurried in the fluid, but precipitated solids also can deposit on the walls of the production equipment, which ultimately causes high pressure drops, plugging, and flow stoppage. Control of this deposition by prevention and/or mitigation is the essence of flow assurance.

Wax in hydrocarbons is primarily paraffin, which is a white, odorless, tasteless, chemically inert compound composed of saturated hydrocarbons. The linear paraffins are easily measured by high-temperature gas chromatograph (HTGC).

Two critical issues require special attention: gel formation (precipitation) and deposition. A hydrocarbon gel forms when wax precipitates from the oil and forms a 3D structure spanning the pipe. This condition does not occur while the fluid is flowing because the intermolecular structure is destroyed by shear forces as soon it is able to form. However, when the fluid stops flowing, wax particles will interact and join together, potentially forming a network resulting in a gel structure if enough wax comes out of solution. In a pipe, wax deposition results in flow restrictions. Slow buildup of wax layers in pipelines and flowlines is caused by the solidification of the paraffinic fractions on the cold inner surface of the pipe wall. Wax deposition is expected during steady-state operation in the flowline where the production-stream temperature is below the wax-appearance temperature (WAT). The deposition rate depends mainly on the fluid characteristics, flowing and pipe-wall temperatures, heat flux through the pipeline, and the shear stress at the wall.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper OTC 19160, "Design Challenges Due to Wax on a Fast-Track Deepwater Project," by ***Amir Alwazzan,*** *SPE, and* ***Mark Utgard,*** *SPE, AMEC Paragon, and* ***Dalmo Barros,*** *Petrobras America, prepared for the 2008 Offshore Technology Conference, Houston, 5–8 May. The paper has not been peer reviewed.*

Overview

The example field is in the US Gulf of Mexico (GOM), at a water depth of 2,118 ft and a reservoir depth of 18,205 ft measured depth (MD). The system comprises dual 6-in. flowlines running parallel for 17.4 miles from the wells to the host platform. The production system was designed for the two wells to produce 70,000 MMscf/D of gas, 150 STB/MMscf of condensate, and 2 bbl of water/MMscf of gas. The reservoir pressure and temperature are 14,474 psia and 212°F, respectively. The shut-in tubing pressures were anticipated to be high, and the flowlines were designed to a 13,145-psi maximum allowable operating pressure.

The wells were completed with horizontal trees. The trees and the two 6-in. flowlines are connected by two pipeline-end terminals linked to form a pigging loop. One main control umbilical is designed to link the host facility to the subsea-umbilical-termination assembly, which is controlled with an electric/hydraulic multiplexed control system operated from a control-room/operator interface. The wells are equipped with digital-hydraulic-pressure-transformation sensors and the trees with production and annulus-pressure sensors. All pressure- and temperature-sensor data are displayed at the control-room/operator interface and saved for future reference. The production system is equipped with topside chemical-injection, umbilical, trees, and well systems to provide paraffin and hydrate inhibitors.

Wax Deposition: Control and Management Strategy

The lack of necessary information was a great technical challenge. Generally, the flowlines were designed for steady-state-production conditions, in accordance with a base-case production forecast, base-case well-temperature profile, and minimum ambient seabed-temperature profile. In addition, a key line-sizing criterion was to achieve a large degree of operational flexibility (i.e., turndown flexibility in each of the two multiphase-transport pipelines without mitigation actions such as dynamic pigging).

Fluid Sampling. In-situ-reservoir-fluid samples consisted of gas condensate, with liquid gravities ranging from 34.7 to 37.4°API. The fluid is a rich gas condensate with a yield of approximately 160 STB/MMscf or a gas/oil ratio of 6,253 to 6,474 scf/STB.

Wax Analyses. Three studies were carried out by different parties during front-end engineering design.

Study 1. This study was carried out to determine the WAT. The collected samples were heated to 170°F at a pressure of 17,000 psig and mechanically agitated for 24 hours before any subsampling. After pressure and temperature restoration, the subsurface gas samples were transferred in single-phase to a pressure/volume/temperature cell, where they were expanded to the required test conditions of 1,300 psig at 68°F. Results of the flowing-temperature-profile test indicated no detectable pour-point temperature or gelling tendency. The WAT of the 1,300-psig condensate was measured with a near-infrared (NIR) closed cell. The WAT of the 1,300-psig condensate liquid was determined to be 124°F.

Study 2. A live-oil isobaric NIR study was conducted to determine the WAT, construct the wax-deposition envelope (WDE), and determine several experimental points on this envelope. The data indicate a WAT of 95°F (dead-liquid condensate). The shape of the WDE indicates that it would be possible to limit wax formation by providing adequate insulation and/or heating of the conduits carrying the fluid. These options were considered uneconomical, so the challenge of potential wax-deposition problems in the subsurface and surface facilities remained.

Study 3. The objectives of this experimental study were to conduct detailed characterization of the condensate and determine its WAT and pour point. The characteristics of the condensate typically are paraffinic in nature. The detectable *n*-alkane carbon-number distribution was up to C56 in the condensate-analysis content, determined by HTGC.

The WAT of the condensate was found to be 109.8°F through cross-polarized microscopy. The minimum and maximum pour points were measured under atmospheric pressure and found to be 0 and 5°F, respectively (expected to be lower under actual flowline operating conditions). The low congealing potential under operating temperatures was confirmed by rheological study.

The evidence of formation of a very weak gel structure at 25°F, however, confirmed that congealing oil is not a concern under the 40°F seabed operation conditions. Because the pour points are much lower than the minimum operating-temperature range (40°F at seabed), production problems related to high viscosity, congealing oil, or pour point are not expected.

All of the studies indicated that this field's condensate exhibits a severe wax-deposition tendency at flowline-operating temperatures. Design calculations, considerations, and assumptions must consider this reality. The most conservative numbers must be considered to design for the worst possible scenario.

Steady-State Analyses. The steady-state-modeling strategy involved modeling the thermal/hydraulic performance of one 6-in. flowline at key conditions to define the operating envelope. This study was carried out with a simulation program. The robustness of the design, in terms of hydrate control, wax management, slugging,

and blowdown, then was tested against the various scenarios and changing conditions to ensure continual operability and, where necessary, updating of flow-assurance strategies. A drastic change in the slope of the heat-loss line appears at 136°F downstream of the choke, to the ambient temperature of 46°F within a distance of less than 1 mile. Thus, the operating plan requires that paraffin inhibitor be injected.

On the basis of the static-temperature gradient, the surface-controlled subsurface valve (SCSSV) was designed to be set at a depth of 9,500 ft MD. The simulation results regarding liquid-holdup variation across the system aided in deciding where to place the SCSSV and the paraffin-inhibitor-injection port. During steady-state operation, the SCSSV will be covered completely by liquid.

Mitigation. A program of paraffin-inhibitor application in conjunction with pigging operations was recommended. The use of a combined paraffin-inhibitor/pigging wax-management strategy minimizes deferred production and enables easier pigging operations through formation of softer deposit. The benefit of paraffin-inhibitor application in such a case is to reduce the frequency of pigging, thereby potentially saving deferred-production costs.

A decision was made to set the paraffin-inhibitor-injection port at 18,162 ft MD, below the SCSSV. These positions were selected to allow sufficient time for the paraffin inhibitor to mix with the condensate to protect the SCSSV. The selected positions also ensured that all fluid above the SCSSV would be inhibited and would not pose a threat during cold-well startup.

Traditional flowline-pigging operation requires the system to be shut down before launching the pig. This strategy results in significant loss of production for routine pigging. To minimize this production loss, "pigging on-the-fly" may be used. In this method, the flowlines are not shut down or depressurized, and production continues to flow as the flowlines are displaced. The production rate during pigging on-the-fly is reduced from peak flow conditions. The procedure for conducting pigging on-the-fly consists of reducing the flow rates from both wells, directing the flow toward one flowline, launching the pig in one line by use of a gas compressor, and then (by using the produced gas) completing the pigging of the remainder of the loop.

Conclusions

Flow-assurance threats can be identified and handled if they are discovered early followed by implementing proper system design and operation procedures. To select and deploy an appropriate flow-assurance strategy, a fundamental understanding of each solid's characteristics is essential. Otherwise, minimizing capital and operating expenditures while minimizing risk is difficult. To determine which problems may affect a given system, high-quality oil samples are needed for analysis and testing. As a rule of thumb, always design for the worst possible case because early samples may not represent the produced fluid because of contamination or slight fluid changes.

Like most of the fields in the GOM region, several unique characteristics contributed to the flow-assurance challenges associated with the Cottonwood field discussed in this paper. A systematic flow-assurance analysis was performed during both front-end engineering design and detailed engineering. **JPT**