Mexico case study exemplifies MPD success in deep depleted fractured carbonates

By Aaron Miller, Halliburton Energy Services, and Antonio Urbieta, PEMEX

In this MPD project, cryogenic nitrogen was phased out in favor of membrane nitrogen equipment, which provided cost reductions and eliminated logistics concerns with cryogenic nitrogen supplies.

A 33-WELL, integrated-services drilling project in the Bermudez and Jujo Fields in Southern Mexico was recently completed along with the development of several innovative managed pressure drilling solutions to overcome some critical operational challenges. PEMEX operates these fields and, from previous experience, knew that they would be facing significant drilling challenges, particularly in the pay-zone sections. This article will focus on the techniques and equipment used to successfully drill these wells and overcome these challenges.

The project was to be executed in fields discovered in 1972 that contained significant oil in place. Unfortunately, because of significant pressure declines since first discovery, major drilling challenges needed to be resolved for the project to be successful. The pay-zone is made up of highly permeable fractured carbonates. While this is an excellent production characteristic, it makes drilling difficult, especially when the reservoir is very compartmentalized in various fault blocks, each with widely variable pore pressures.

SAME PROBLEMS AGAIN

When PEMEX reviewed the offset wells and historical drilling practices, they found that the same problems had surfaced, and they had started using low-density nitrified fluid systems in 1996. The reduced equivalent mud weights had been used to drill these zones as near balanced as possible to minimize fluid losses. While the low-density fluid systems did achieve some success, reservoir pressures had declined in some blocks to considerably less than when the offsets were drilled. It was expected that each pay-zone would have pressure gradients ranging from 2.0 ppg up to normal.

The question, then, was how to design a drilling system for the pay-zone that would be flexible from 2.0 ppg up to 8.34 ppg and would precisely dial in a minimum amount of overbalance. A narrow margin of overbalance would minimize fluid losses to the formation and facilitate good hole-cleaning. Loss-control material (LCM) could not be considered an option because of production impairment reasons and for contractual compliance.

A managed pressure drilling system was selected as the best option to manage and monitor the annular returns to ensure that the bottomhole pressure was at the right equivalent circulating density (ECD) to drill the well with a very low margin of overbalance. Careful and precise management of downhole annular pressure would prevent bulk fluid and cuttings losses to the reservoir and would prevent hydrocarbon and potential H_2S production to surface.

Additionally, the system would be required to safely manage the flow of any underbalanced kicks that might occur while the MPD parameters were adjusted so that the system would return to the ECD set-point safely and expeditiously. Any produced hydrocarbons would be diverted and segregated into a closed storage system, away from the open mud tanks.

DEFINING PORE PRESSURE

Well control and ECD management in this section would first require well-defined reservoir pore pressures to know what target parameters would be needed. In areas with unknown reservoir pressures, static fluid-level measurements would be needed to set target drilling ECDs and provide a 0.15 ppg to 0.50 ppg level of overbalance. Well-control techniques and kick detection methods would have to be amended. Bottomhole annular pressure and ECDs would be dependent on additional variables, including applied back pressure and ratio of nitrogen to liquid pumped. Primary ECD control would be maintained with nitrogen and fluid injection rates, while fine-tuning would be performed by adjusting annular back-pressure.

Kick and loss detection would include

instantaneous comparison of pump and nitrogen rates injected into the standpipe versus the rates of drilling fluid and nitrogen leaving the separator. Careful prediction of the expected change in liquid holdup with a MPD parameter change also had to be considered to avoid erroneous kick-detection alarms, since liquid holdup is the volume of liquid in the hole at any given time and depends on the nitrogen and pump rates as well as annular back pressure.

Drill-string connections would require specialized procedures in order to maintain the level of overbalance as accurately and with as much stability as possible. Rigs with top drives to reduce the number of drill string connections required in the MPD section would be selected.

Tripping operations also would require specific procedures usually not considered in conventional drilling operations. For example, the hole would be filled only by the steel displacement of the tripped-pipe volume up to but not above the static fluid level.

COVERING ECD RANGE

Since a single nitrified fluid system to cover the entire ECD range was not available, 2 interchangeable systems were designed to work in tandem so that the lowest to highest ECD required could be accommodated. A recyclable high-temperature foam system was designed for the 2.0 ppg to 5.0 ppg range while a 2-phase fluid system – nitrogen and drilling fluid – would be used to handle the 4.0 ppg to 8.34 ppg range. The recyclable foam-fluid system was designed with 2 additional components when compared with the traditional 2-phase system – the additions were a foaming surfactant and a defoaming breaker to defoam the drilling fluid as it reached the surface, enabling it to be separated into nitrogen, fluid, and cuttings in the separator.

Fluid-system pilot testing was performed prior to drilling the first well, especially since the recyclable foam system would have to be capable of performing at depths up to 20,000 ft with bottomhole circulating temperatures up to 275°F. Testing in a research facility prior to commencement of operations confirmed that the foam retained the proper rheology for hole-cleaning and ECD control at downhole circulating conditions. The 2 fluid systems had to have 100% compatibility in order to retain the flexibility of alternating from one system to the other easily. Additionally, the foam system had to be as recyclable as possible in a closed system due to environmental regulations and the high disposal costs of the base fluid.

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Design-safety philosophy of the MPD system specified that it would not replace any of the existing well control equipment. The rotating flow diverter (RFD) would function in addition to the annular preventer; it would not replace it. The MPD choke manifold would be a dedicated manifold and flow line and would not replace the rig choke manifold.

Nitrogen would be used to generate the lightened drilling fluids, and initially, cryogenic nitrogen equipment was planned for this purpose. Early in the project, cryogenic nitrogen was phased out in favor of membrane nitrogen equipment to provide cost reductions and eliminate logistical concerns with cryogenic nitrogen supplies. (Air was ruled out as an injection gas alternative for safety reasons.)

Although the MPD objective was to maintain a low overbalanced drilling condition without reservoir inflow, equipment would have to be installed and the wells designed to safely take and manage a kick situation without requiring shut in. Depending on the hole size, depth, and reservoir pressure, either a 2,000, 3,000 or 4,000 scf/min. membrane nitrogen package would be needed. The membrane nitrogen package selected was the 4000 scf/min. x 5000 psi.

An injection-control manifold would be used to rapidly and safely pump nitrogen to the standpipe, divert nitrogen from the standpipe to vent for drill string connections, and bleed off the standpipe pressure. It would also provide an injection point for foaming and corrosion-control chemicals and a shearing foam generator to improve the performance of the foam system.

RIG MODIFICATIONS

- A check valve would be installed between the rig pump and the standpipe;
- All NPT connections in contact with nitrogen would be replaced with welded connections;
- Rotary hoses would be subjected to a rigorous inspection and evaluation process before being used with nitrified fluids.

Specific MPD downhole equipment would include non-ported non-return valves (NRVs) or floats in the drill string and in the bottomhole assembly (BHA), corrosion rings to monitor the corrosion inhibition program, and an annular pressure memory tool to validate the ECD predicted by flow-modeling computer software to be sure that it was in agreement with actual drilling conditions.

A rotating flow diverter with dual sealing elements would be used to divert the pressurized annular flow of nitrogen, fluid, and cuttings to the downstream MPD equipment.

CHOKE MANIFOLDS

A remotely operated MPD choke manifold in addition to the rig's standard choke manifold would be used to step down the pressure of annular returns before the mixture entered the 3-phase separator (gas/nitrogen, drilling fluid, and cuttings).

A pressurized vertical 3-phase separator capable of handling surges of up to 50 MMscf/D gas/nitrogen, liquid rates of up to 35,000 bbl/day, as well as 1,800 bbl/day of drill solids would be used. The produced nitrogen from the separator would be sent to a flare pit with a continuous ignition system to safely handle any produced hydrocarbon gas in a kick situation.

The solids slurry and the clean drilling fluid then would be sent through a diverter manifold to the rig's solid-control area and open-rig-tank system. In the case of hydrocarbon or H_2S detection at surface, the diverter manifold would be used to divert to a closed tank system while the kick was circulated out and the overbalance margin re-established.

Data-acquisition equipment would be used to gather sensor measurements from the rig and MPD equipment and would display it at key decision-making locations on wellsite as well as in an operations-control center off location. This data would be used to update the downhole flow model and provide a means to adjust MPD parameters to optimize the ECD and hole-cleaning requirements.

The most important aspect of making this drilling system run smoothly was the wellsite operational and support teams that would be responsible for making certain that everything would function properly. A wellsite MPD supervisor, like the rig tool-pusher, would report directly to the company man on location and would serve as the communication link to the rest of the crew.

Training of supervisors, engineers, 7 rig crews and 4 MPD equipment crews would be critical to ensuring a smooth and safe operation. Therefore, in addition to pre-project training sessions, pre-operational planning meetings, job safety analyses and toolbox talks were planned for the wellsite prior to beginning the MPD operations and before performance of any non-routine operations.

RESULTS, THE FUTURE

The operations in the Mexico project were run as planned, and the results for MPD operations were impressive. Proven techniques were modified and refined to address the demanding hole sections and varying hole conditions. Drilling operations were performed according to plans. Kick situations were safely and effectively managed, allowing drilling to be resumed with a minimum amount of down time. Well cleanup times were reduced by keeping the volume of fluid losses to a minimum.

The pressurized separator used was capable of handling surges of up to 50 MMscfd gas/nitrogen, liquid rates up to 35,000 bbl/day, as well as 1,800 bbl/day of drill solids.

Techniques and advances developed to address the needs of this project will be applicable to many analogous fractured and under-pressured carbonate reservoirs throughout the world. This success has shown that when MPD is applied properly, it can provide a safe and effective drilling solution for the well types discussed here and can unlock previously inaccessible reserves as well as reduce overall lifting costs.

In these oilfields, state-of-the-art MPD techniques will continue to advance, and a new project that will be taking this technology and lessons learned from this project and extending them has already started. Additional technologies being evaluated for future work in these fields include extended range electro-magnetic measurement while drilling (EM-MWD), oil-based fluid systems, and a step-change to enable candidate wells to be drilled in true underbalanced conditions. This capability would enable real-time evaluation of reservoir productivity, which would further benefit operations in difficult completion scenarios such as those PEMEX has undertaken in Mexico.

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