Drilling and testing of an HPHT deep gas prospect from an existing well: case history

By M.J. Al-Saeedi, J.R. Singh, V.S. Mahesh, H.S. Al-Ajmi, Kuwait Oil Company; D. McKinnell, Total Kuwait

THE SEARCH FOR commercial quantities of non-associated gas from the Lower Mesozoic and Paleozoic horizons has been an important part of the exploration strategy of Kuwait Oil Company (KOC) over a number of years. Four deep wells were drilled down to the Pre-Khuff formation in the existing oilfield areas of Burgan, Umm Gudair and Subriyah, before gas shows were recorded from the Sudair formation in the fifth well, KM-1, in the Kra Al-Maru area (Figure 1).

Following this result, further evidence of gas shows were recorded from the Unayzah formation in North West Raudhatain-1, and strong indications of a free gas potential were seen during the drilling phase on Mutriba 10, where high-pressure influxes were encountered while drilling the Sudair formation. This potential was borne out in the subsequent Mutriba well, MU-12, which tested the first measurable quantities of non-associated gas in Kuwait from the Sudair in 2004.

Following the success in MU-12 and the indications of gas in KM-1, it was decided to return to the Kra Al-Maru area for the re-entry and deepening of KM-3.

Well KM-3 was located near the crest of the Kra Al-Maru structure some 450 m from KM-1. Although the original drilling and evaluation of KM-3 had indicated some hydrocarbon potential in the Najmah/Sargelu, logs and cores suggested that there was only limited porosity development in the primary targeted Marrat zones. The well was therefore suspended without running the liner across the open hole with a future possible decision to deepen the well depending on engineering feasibility as well as the test results from MU-12, which had not been completed at the time of KM-3 suspension.

The subsequent engineering feasibility study showed that it was technically possible to deepen the wellbore and that it was also economically viable when compared with the cost of a new well. Therefore KM-3 was selected as a suitable candidate for deepening to the Sudair formation, and detailed design studies were undertaken.

WELL DESIGN, PLANNING

The original well design for KM-3 was based on a “big-hole” casing program commonly used in Kuwait for drilling deep exploratory Marrat wells. Because of reduced pore pressure and wells encountering severe loss/gain situations in the fractured Najmah/Sargelu, a 7 ½-in. liner is usually run to isolate the Najmar/Sargelu sequence and the Marrat is then drilled in 6 ½-in. hole. In this part of the Kra Al-Maru field, however, the pore pressures are higher and the differential pressure between the two zones less pronounced. Therefore it was possible to commingle the Jurassic formations in the primary targeted Marrat zones in the same hole section on both KM-1 and KM-3 wells (Figure 2).

Figure 1: Four deep wells were drilled to the Pre-Khuff formation in existing oilfields before gas shows were recorded from the Sudair formation in the fifth well, KM-1.

Several hole and casing design combinations were possible. These are listed as follows and are shown in Figure 3:

**Design 1**
- Drill 9 ½-in. hole / Run 7 ½-in. liner to top Sudair
- Drill 5 ⅞-in. hole / Run 4 ¼-in. liner from top Khuft to 300 ft above 7 ½-in. shoe
- Run 7 ½-in. tie-back to surface

**Design 2**
- Drill 9 ½-in. hole / Run 7 ⅜-in. liner to top Sudair
- Drill 6 ¼-in. hole / Run 5 ½-in. liner from top Khuft to 300 ft above 7 ⅜-in. shoe
- Run 5 ⅞-in. x 7 ½-in. tie-back (5 ½-in. to top of 7 ¾-in. drilling liner) to surface

**Design 3**
- Drill RWD 9 ⅜-in. x 10 ½-in. hole / Run 8 ⅛-in. liner to top Sudair
- Drill RWD 7 ⅜-in. x 8 ½-in. hole / Run 7-in. liner from top Khuft to 300 ft above 8 ⅛-in. shoe

Figure 2: The KM-1 offset drilling records indicated the possibility of designing a casing program such that the formations down to the top of the Sudair would be drilled together without the need for an intermediate liner at the base of the Marrat. This would allow the final hole section to be drilled through the prospective reservoir to a TD in the base Sudair / top Khuft.
**Run 7-in. x 7 ½-in. tie-back (7-in. to top of 8 5/8-in. drilling liner) to surface**

In Designs 2 and 3, the production liners (5 ½-in. / 7-in.) have been extended to cover the previous drilling liners to allow for the production loads.

The final decision was for the adoption of Design 1. After running safety factor calculations for the casing and liner combinations, the following casing program was chosen:

- 7 ½-in. liner, 70.7 lbs/ft, Q-125, premium connections
- 7 ½-in. tie-back, 70.7 lbs/ft, T-95, premium connections
- 4 ½-in. tie-back, 18.8 lbs/ft, Q-125, premium connections

**Production Loading Safety Factor**

The next main decision point was the cementation of the production tie-back casing in relation to the production loads generated under the tubing leak scenario. The criteria taken were: a Sudair pore pressure of 19 ppg, gas to surface, and a supporting gradient of 8.4 ppg (water) for the cemented tie-back.

With these criteria, it was not possible to use an overbalanced completion fluid with a tie-back cemented to surface and still maintain a 1.2 safety factor for burst. Therefore the design loading was run with a series of underbalanced completion fluid weights and cemented lengths. 11.2 ppg calcium chloride brine was selected, which allowed the maximum length of production tie-back to be cemented.

**BOP / wellhead rating**

The pore pressure of 19 ppg considered for the Sudair resulted in a Production MASP of 15,970 psi. The drilling loading MASP, based on ½ void situation, was 10,450 psi.

Given these figures, it was planned to drill the well with a 15,000-psi WP wellhead and BOP system (4-Ram), and increase to 20,000-psi WP for the tubing head and Xmas tree assembly. Likewise, the test tubing, downhole packers and equipment were rated in line with anticipated Sudair pressure.

**Well material and equipment planning**

Following the establishment of the major design points, the long lead equipment items were identified and ordered, and a basis for the detailed well planning was established. The major items included:
**Drilling Fluids**

The drilling fluids program adopted for this well had to be tailored to handle formations with high pore pressures and complex lithologies. In the Kra Al-Maru area, KOC finds some of the highest pressured zones in Kuwait, with mud weights sometimes approaching the limits for barite weighted diesel oil-based mud systems.

For the re-entry and the two drilling phases, a high-weight oil-based mud system was programmed with a clear fluid calcium chloride brine planned for the well test operations. Details on the individual phases are given below.

### Well re-entry

During the drilling of KM-3 original hole through the Jurassic zones, the mud weight used varied between 18.6 and 18.8 ppg. It was planned to re-enter the well and ream down in stages, circulating out the old mud with new fluid weighted between 18.5 to 18.7 ppg, raising the weight gradually as hole conditions dictated. The unknown element was the amount of barite settlement that may have taken place, and consideration was given to separating displaced fluids for eventual return to the central mud plant for reconditioning.

### 9 ½-in. / 5 ½-in. hole sections

The main drilling fluid properties for the two drilling phases were similar, with some differences due to lithology and pore pressures. The properties of the diesel oil-based muds programmed for the sections are given in Table 1.

#### Well test phase

An underbalanced fluid was recommended for the packer fluid during the well test period. Following the casing design calculations, 11.2 ppg calcium chloride brine was selected. Planning for this type of fluid included the provision of mixing facilities at a central mud plant, separate frac tank storage at rig site and the establishment of a fluid clean-up and displacement planning.

#### HPHT cementing

The pore pressure regime predicted for this re-entry well dictated the need for heavy slurry formulations in the range of 19.5 to 20.0 ppg. With this HPHT environment, particular attention was paid to the design of the slurries. The cementing design verifications were carried out at the North Sea laboratory of the cementing contractor, and KOC employed the services of their IOC consultant to verify and comment on the cementing job proposals.

The key elements of the cementing design proposals are discussed below:

**Temperature**

Accurate estimation of bottomhole circulating temperature and cement slurry temperatures was a requirement for proper slurry design. The usual API schedules can give inaccuracies at extreme conditions; therefore, in addition, a temperature simulation program was run to evaluate the results.

**Slurry designs**

The main consideration for the slurry was the stability at bottomhole conditions. At these higher temperatures, the retarder system is critical. Therefore it was important to ensure that any variations in retarder concentrations or temperature would not be detrimental to the slurry’s thickening time, compressive strength or other properties.

**Spacer design and volumes**

The spacer stability was checked at downhole conditions, especially as it was heavily weighted with solids (barite and manganese dioxide). The spacer volumes were recommended to be larger than those used for standard jobs, given the close weight difference between the different fluids. The spacer system was designed according to an “Erodibility Concept”; therefore the spacer was designed to be more viscous than the mud and less than the slurry.

**Placement considerations**

In an HPHT environment, it is common to have a very narrow ECD window between pore and fracture pressures. In order to prevent losses and gains, HPHT cement job simulators were used with accurate rheological data to determine optimum rates for mixing and displacing. This HPHT rheometer was only available outside Kuwait, so the spacer and slurry designs were prepared well in advance.

**Cement quality**

For HPHT applications, good quality API Class G cement is a fundamental requirement. In KM-3, a recognized cement brand previously used for HPHT cementing in the North Sea and Kuwaiti fields was programmed, blended with 35% silica flour for high-temperature application. In addition to the normal API...
Cement additives

Based on North Sea and Kuwaiti well experience, selected additives were chosen for this well. The properties required in the slurry were: good stability, low rheology, good fluid loss control, good retarder response, fast compressive strength development and good mixability.

The choice of synthetic retarders was important for this HPHT cementing. They have a more linear response and a greater tolerance to changes in bottomhole circulating temperature than do lignosulphonate systems.

One of the most important issues was the quality control of the additives. All of the chemicals reserved for the job had a single batch or lot number, which simplified the lab testing and gave confidence on the behavior of each additive.

Fluids recommendations

7 5/8-in. liner

The planned slurry weight was expected to be 19.5 ppg, with a spacer weight of 19.2 ppg.

Lab test results gave a thickening time of about 10:00 hrs with a fluid loss of under 30 cc / 30 min.

4 ½-in. liner

The slurry design was similar to the 7 5/8-in. liner but somewhat heavier at 20.0 ppg, and the spacer weight 19.8ppg.

Lab test results gave a thickening time of about 9:00 hrs with a fluid loss of under 30 cc / 30 min.

Actual slurries used were heavier than those planned due to formation pressures.

Tubodrilling

In the offset wells for KM-3, the Minjur and Upper Jilh formations were drilled with various bit types using a rotary BHA with low overall ROPs. For KM-3, it was decided to investigate the possibility of using the latest tubodrilling technology in an effort to improve the drilling performance.

One area where the new design of advanced turbodrill motors has been used is in the drilling of hot, deep boreholes. In the Gulf region, such turbines have been successfully run in deep hole applications in fields in Abu Dhabi and Oman.

In the case of KM-3, the design of the latest high-temperature straight hole turbines gave the following advantages over standard rotary or PDM drilling:

- The turbine is an all metallic tool with diamond bearings and thus is unaffected by high downhole temperatures, such as 300°F expected on KM-3.
- The present design of 6 5/8-in. tubodrill has a higher HP power output than earlier tools. Output predicted for the section, drilled with an 18.6 ppg mud, was estimated to be from 316 to 286 HP, at an average surface pressure of 4,100 psi.
- With the use of oil-based mud and given that the turbine is of all-metallic construction, the turbine was considered to have much greater reliability with longer running hours than the elastomer stator PDMs.
- The turbine is not affected by stalling.
- Depending on the mud weight and rheology, the turbine power section (i.e., number of turbine stages and blade type) can be modified for optimum performance.

To obtain the maximum benefit from the output parameters of the turbine, the bit supplier worked with the motor contractor to enhance the design of the PDC bits to provide resistance to abrasive wear at the higher turbine RPMs. The stabilizer pattern used was a fully packed configuration to provide optimum stability and the transmission of WOB without buckling.

Slim-hole coring

With the chosen casing design, the hole size through the reservoir was restricted to 5 ½-in. To core in this size of hole, the choice was between a 4 ¾-in. barrel, which would recover a 2 ½-in. core, or a slim hole 4 ¾-in. barrel, which would cut a 2-in. core. The two problems with the larger barrel were:

- Not being able to fish the barrel with an exterior catch overshot.
- Use of specially manufactured 5 ½-in. core heads.

Slim-hole motors

In order to complete the drilling phase of the well, it was necessary to clean out inside the 4 ½-in. liner after the cementing operation. On the previous deep well, MU-12, slim-hole motors were used with varying degrees of success. For this well the drill string design was thoroughly studied with regard to torque ratings and the possibility of recovery of any fish.

The motor specifications were:

- Nominal diameter – 2 ¾-in.
- Maximum torque – 900 ft-lbs
- Maximum flowrate – 120 gpm
- Motor head features - double check valve, hydraulic disconnect, dual circulating sub.

The drill string for use inside the 4 ½-in. liner was 2 ¾-in. drill tubing, 5.3 lbs/ft, CS-Hydril connection. The torque rating for this pipe was 1,500 ft-lbs. A selection of 3 ¾-in. fixed cutter bits/mills were ordered for the clean out work.

Two related technical problems were present with this drilling assembly; flow rate and mud weight. It would be critical to con-
trol the mud weight value and pump output within a range that was suitable for the motor to drill effectively.

**DRILLING OPERATIONS**

The well was re-entered and drilled to TD in 79 days against a planned figure of 54 days. The drilling curve is illustrated in Figure 4.

### 9 7/8-in. Phase

**Re-entry and clean-out of original hole**

The initial operation of cleaning out the cement and suspension plug to 10 3/8-in. shoe at 14,936 ft required excessive reaming from about 7,000 ft onwards; probably due to barite sagging as the mud left in the original hole was not treated with viscosifiers for long-term suspension.

As the 9 7/8-in. open hole was cleaned to 15,419 ft, gas levels increased and the mud weight increased to 18.9 ppg. During the subsequent flow check the well was found to be flowing and on resuming circulation, losses occurred. Therefore, LCM pills were pumped to plug the loss zones and the mud weight was gradually raised in attempt to stop the flow on the annulus.

This loss/gain cycle continued during the reaming of the previously drilled open hole down to the original TD of 16,682 ft. At this point, mud weight had been increased to 19.2 ppg. Attempts were made to deepen the hole using this mud weight, but drilling was stopped at 16,700 ft due to further flows and losses. At this point, total fluid losses had increased to 7,490 bbl and total LCM pumped was 1,960 bbl.

Mud weights were now much higher than those seen during the original drilling and, given the narrow range between loss and gain, a decision was taken to squeeze cement across the entire open hole section to try and seal off the problem areas.

200 bbl of 19.5-ppg cement was squeezed through a retainer set above the 10 7/8-in. shoe into the open hole, the mud weight cut to 19 ppg and firm cement cleaned out to a depth of 15,355 ft, following which the hole was washed/reamed to the existing TD at 16,700 ft with no further losses or gains.

**Drilling to the Jilh Salt Formation**

Rotary drilling continued with a PDC bit to the top of the Minjur formation (16,985 ft), where penetration rates came down from 7 ft/hr to 2 ft/hr by 17,450 ft, with the formation consisting of firm shales. The penetration rates continued to remain low, even when the mud weight was lowered to 18 ppg above the Jilh formation at 17,570 ft, where the estimated pore pressure had reduced to 17.6 ppg. With such low ROPs, it was decided to pick up the turbine.

A 6 7/8-in. turbine was run with a new 9 7/8-in. PDC bit. Initial penetration rates of 6 ft/hr were reduced to 4 ft/hr, and a trip was made to check the condition of the bit, which was only 5% worn. A different design PDC bit was picked up, and drilling rates increased, from 6 ft/hr up to a maximum of 15 ft/hr at the top of the first Jilh salt (18,107 ft).

Drilling continued to 18,292 ft, where a kick was encountered and was shut in with 1,540 psi on the drill pipe (equivalent to 19.6 ppg mud). On first circulation, the mud weight was cut to 16.5 ppg with the influx being salt water. After the second circulation with 19.5 ppg in and out, the BOF was opened and the well circulated at 300 gpm with an ECD at 20.3 ppg, which held the formation.

Attempts were made to continue drilling while combating the loss/gain cycles. At 18,331 ft with partial losses at 30 bbl/hr and a mud weight of 19.6 ppg, it was necessary to trip the string to remove the turbine. To control the formation flows, the mud weight was raised in stages to 19.9 ppg. On attempting to trip, the well was not taking the correct amount of fluid, therefore the drill pipe volume was bull-headed and 20.5 ppg kill mud pills pumped into the annulus during the rest of the trip to control this tendency to flow.

As it was not possible to continue drilling with this high mud weight, it was decided to attempt to stabilize the lower part of the hole by squeezing cement. A cement retainer was run, and 300 bbl of 17 ppg cement was squeezed into the open hole.

Following a negative test to 19 ppg, the mud weight was reduced to 19.5 ppg, and the hole washed and reamed to 16,400 ft, where a 7-bbl gain was registered on a flow check (SIDPP 810 psi, MWE 19.95 ppg). The mud weight was raised to 19.9 ppg, and washing and reaming continued up to 18,331 ft through patches of firm cement.

New hole was drilled to 18,390 ft, where the well again flowed at 50 bbl/hr. The mud weight was raised to 20.2 ppg, and the well again went into a loss/gain cycle. At a final mud weight of 20.4 ppg, the well was put on losses to trip.

With the well in this critical state at the limits of the conventional mud weights and with the experience from well KM-1, where Minjur to top Khuff were drilled in the same hole size, the decision was taken to run the 7 7/8-in. casing earlier than its programmed setting depth. It was further evaluated that this would at least secure the Jurassic objectives, while giving a better chance to reach the deeper horizons.

This salt water flow from the Jilh salt/limestone sequence was not seen on the offset well KM-1. Total losses since problems were encountered in the Jilh Salt sequence were 5,140 bbl.

**Running the 7 7/8-in. liner**

The 7 7/8-in. liner string was run with the well in a static condition. There were no returns on breaking circulation with the liner shoe at the 10 7/8-in. shoe, or at the setting depth.

The 7 7/8-in. hanger did not set, and the string was cemented on bottom with 100 bbl of spacer and 150 bbl of 20.5 ppg cement. The cement weight was heavier than first proposed, but the properties were fully tested prior to the job. There were no returns while circulating or cementing with total formation losses being 1,032 bbl. The liner top packer was successfully set after the cement displacement.

The mixing of the slurry was as per the pre-job simulations, but one point of concern was the high pump pressures needed when attempting to reverse out after the job. This had also been seen on the previous two cement squeeze jobs. After investigation, it was recommended for future jobs to change the spacer chemical and to use a drill pipe wiper ball to remove any residual cement from the DP.

**5 ½-in. phase**

**Drilling to core point in the Sudair**

Tieback of the 7 7/8-in. liner to surface, prior to drilling out, was then discussed. The vulnerability of the 10 7/8-in. casing due to the number of rotating hours, was weighted against the flow/standpipe pressure restrictions imposed by using a full 3 ½-in.
drill pipe string to surface. In the end, the condition of the 10 7/8-in. was considered acceptable for drilling to continue.

With the shoe integrity checked up to an EMW of 20.1 ppg and a 19.6 ppg mud weight, a 5 ½-in. hole was drilled to 18,512 ft, where losses were encountered at 60 bbl/hr in the lower part of the Jilah formation.

The open hole was cemented through a 7 7/8-in. cement retainer, and cement drilled out with the lower mud weight of 18.8 ppg. Drilling continued without further incident into the Sudair formation (top at 18,695 ft) to a core point at 18,730 ft.

Coring and drilling to TD

A 60 ft x 4 ¾-in. core barrel was made up with a 5 ⅛-in. PDC corehead, and six cores were cut through the Sudair into the top Khuff to 19,045 ft. The mud weight at the start of the section was 18.8 ppg, and this was raised to 19.2 ppg following an influx with increase in gas count plus chlorides during the cutting of core No. 5.

A 5 ⅛-in. PDC bit was run, and drilling continued in the Khuff to 19,057 ft, where losses started at 30 bbl/hr. An LCM pill was pumped, and the section drilled to 19,077 ft, where losses again occurred. At this point, drilling was shut down to change out the wash pipe. During the repair process, the well was closed-in, and 500 psi pressure was recorded on the annulus.

The influx was circulated out, and the mud weight raised back to 19.2 ppg. On attempting to POH with the string, the well started to flow (ECD during the drilling being estimated at 19.5 ppg). The well was closed-in, and the mud weight raised in stages up to 19.8 ppg.

The hole was then reamed down to 19,053 ft, with high torque and losses (17% returns). LCM pills were pumped, but the losses increased with only 5% fluid returns. The well was observed as static at this point, and the drill string pulled out to the casing shoe. After checking for flow, the bit was pulled to surface, with the mud level not visible during the trip.

With the hole again in an unstable condition, a further squeeze with acid soluble cement (17.5 ppg) was carried out through a retainer. On drilling out the cement, flows and losses were again evident, and the mud weight was once more increased to 19.9 ppg due to a CO₂ influx.

The well was put on losses by bull-heading 22 ppg mud slugs down annulus and drill pipe, and the bit was pulled to surface. Once on surface, it was found that the bit had lost all three cones. In order to re-stabilize the well, a second cement retainer was set, and 100 bbl of 17.5 ppg acid soluble cement was squeezed below. On pulling out the string, it was found that there were no returns during the job.

Running 4 ¼-in. liner and 7 7/8-in. tie-back

The 4 ¼-in. liner string was run with partial to no returns. The liner was hung and cemented with 35 bbl of 20.0 ppg cement slurry. The cement plug was not bumped, and no returns during the job. On attempting to pull out the liner setting tool, there were indications that the liner had not been released. When the string was pulled to surface, the liner hanger was found to be held by the pack-off bushing dogs, which had not released.

Hard cement wasreamed out during the clean-out trip to the liner TD at 19,030 ft. On observing the well, it was found to be flowing at 80 bbl/hr; therefore attempts were made to put the well on losses by pumping high weight slugs, which resulted in partial returns of 79%. The well continued to flow, and the mud weight was raised in stages to 20.1 ppg with mud losses of 50%. 22 ppg slugs were again bullheaded into drill pipe and annulus to trip the pipe.

The same liner hanger was reconditioned and the shoe modified with v-set blades on the nose, to aid release. The 4 ¼-in. liner was re-run, with no returns and fluid level static at the wellhead. The liner was released on bottom and cemented with 35 bbl of 20.5 ppg cement. Again the plug was not bumped, and there were no returns during the job.

To ensure isolation, a 7 7/8-in. cement retainer was set at 17,706 ft and the top of the liner squeezed with 30 bbl of 20 ppg cement. After cleaning out and polishing the PBR, a liner top packer was run and set, and negative tests were carried out to 10.5 ppg EMW at the top of the 4 ½-in. liner, and to 16 ppg EMW on the 7 7/8-in. liner lap. The mud weight was reduced to 16 ppg and the 7 7/8-in. casing tie-back was run and cemented with 180 bbl of 16.5 ppg cement.

End of well operations

Clean out and preparation for Testing

A 3 ¾-in. mill plus 2 ¾-in. slim-hole motor were run on 2 3/8-in. drill tubing, and the 4 ¼-in. liner was cleaned out to 18,912 ft, where the wiper plug assembly was tagged. Given the limited performance of the motor to this point, the mud weight was lowered from 16 to 14 ppg in an attempt to improve the motor parameters. Two further mill runs, including a change of motor, were made but, it was not possible to clear further than 19,015 ft; therefore the motor was laid down.

It was decided to try a slightly reduced diameter mill (3 ¾-in. OD) and to run it on a rotary assembly. A close watch was paid to the torque levels during drilling given the use of the 2 ¾-in. drill tubing.

The plug assembly was drilled up, without undue torque problems and the cement plus shoe track cleaned out to a plug back TD of 19,040 ft. This left a remaining length of 10 ft of cement above the liner shoe. It was a requirement to drill up this much of the shoe track as the zone of interest extended down to the top of the Khuff formation.

The 4 ¼-in. liner shoe was negative tested to 10.5 ppg EMW, followed by a positive pressure test of the entire column.

The drilling mud was displaced to brine in several circulation steps, due to the circulation pressures involved. First the oil-based mud was reduced in density from 14 to 12.5 ppg. This was followed by the circulation of scavenger / surfactant pill train to remove the oil base mud ahead of the 11.2 ppg calcium chloride brine. An extended observation period was applied to check the well for any flow back. The fluid movements due
to temperature effects were plotted in order to check for any traces of abnormal fluid flow.

Cased hole logs were then run and preparations made for testing. It was noted that the CBL log showed fairly good cement across the 4 ¼-in. liner, particularly around the liner shoe and above the zone to be perforated.

WELL TESTING
The planning of a well test with 20,000-psi rated equipment was as challenging as the design and procurement for the drilling phases of the well. The specialized equipment necessary for such HPHT testing is fairly unique, and only a few sets are available worldwide. KOC decided early in the planning for this well that a dedicated team should be established to be responsible for the testing aspects.

KOC organized well test specialist support for the programming and supervision of the tests with the assistance of their IOC engineering consultant. These technical experts were integrated into the team once the drilling phase got under way, in advance of the testing period. Their work scope was split into a pre-planning / design phase followed by an operational phase.

Well test design
The DST test string design was based on objectives of the well test, plus the experience learned from the 20,000-psi well tests carried out on well MU-12 and from HPHT testing globally. The general system design was that of a tapered string, with the DST / TCP BHA stabbed through a permanent packer.

Results and performance
In the absence of any defined logging information, the decision was taken to perforate and test for hydrocarbon prospects the available footage in the Sudair and top Khuff.

After acid stimulation, the well was cleaned up and flow-tested on various choke sizes. This clean-up was hampered by the salt precipitation and plugging of tubing and surface chokes.

CONCLUSIONS
The deepening of KM-3 has been highly challenging due to the differences in lithology and pressure regime from those of the offset well KM-1, the pressures encountered during drilling being higher than those predicted, a very narrow window between gains and losses.

Even with these associated risks and problems, the well has been deepened to target and successfully tested in less time and with less expense than drilling a new well. This was primarily due to the thorough engineering and planning works that were undertaken early in the project, plus the high level of well site supervision and good cooperation of the rig contractor.

Utilization of the latest technology and products in HPHT cementing gave good results during the slurry mixing and displacement, the only problem being the reaction of the spacer during primary and squeeze cementing.

The use of turbine and slim downhole motor technology gave mixed results. The turbines were reliable and gave some increase in the ROP. However, there were some limitations with the slim-hole motor performance.

The extended testing of a deep gas zone with 20,000-psi rated equipment and the recovery of downhole pressures, rates and samples has fully proved the application of this specialized well test technology for other deep gas wells in Kuwait.

This was the first extended test of a deep gas zone in Kuwait, and it showed that the well has a potential to produce commercial quantities of gas and condensate.

This successful deepening and testing of an existing well in a severe pressure environment has provided valuable lessons that can be applied to the drilling of future wells of this type. These lessons and recommendations include the following points:

Well design
- Due to a change in pore pressure regime and risk of heavy losses in the Khuff, plus possible well control with the Sudair, it is necessary to isolate the Sudair from the Khuff with a dedicated casing string.
- Well designs for these HPHT prospects should be planned with a contingency casing string. In the case of unpredicted high pressures or reduced loss / gain window, a string may have to be run earlier than programmed.

Well material, equipment planning
- After the completion of detail design stage, a long-term planning and follow-up procedure should be put in place to track the special order material items.
- Well test equipment rated to 20,000 psi needs to be organized and committed for early in the well preparation phase, followed by regular contact with provider.

Drilling fluids
- Suspended wells programmed for eventual re-entry should be suspended with OBM treated to packer fluid specifications.
- Heavy losses in both hole sizes, General LCM mix gave partial / temporary seal, investigations to be made into advanced polymeric based LCM technology.
HPHT cementing

- For squeeze jobs using high-density cements and spacers (over 18.0 ppg), use compatible spacer chemical with rig supplied barite. Spacer volumes to be increased to clean drill pipe.
- Use drill pipe wiper ball to remove any residual cement from the DP during cement squeeze jobs.

Downhole motors and rental tubulars

- Turbodrills to be considered for future drilling of deeper formations. They gave ROP increases compared with rotary assemblies, with no equipment failures or evidence of down-hole vibration. A circulation sub should be run to allow pumping of coarse LCM.
- Found 2 3/8-in. CS-Hydril tubing suitable for rotation and cleared plugs and cement inside the 4 ¼-in. liner.

Liner hangers / tieback

- Procedure to be developed in conjunction with supplier for effective disengagement of liner running tool after cementing to ensure deep set, lightweight liners, in heavy mud weights do not travel up.

Testing

DST and TCP

- Effective makeup OD of eccentric tools must be verified by the supplier with reference to the limiting string OD that can be run in the wellbore (i.e., vendors gauge carrier could not be run due to an oversized effective OD).
- DST tools are designed to stay in the hole for relatively short testing duration (within a month). In the case of KM-3, DST tools were in the hole for over 28 days, and they all functioned as designed. Contingency plans must be considered in case the tools are to be kept in the hole for longer. In this well, minimum downhole tools were used and two reversing valves were run.
- Designing the job with bigger ID permanent packer would:
  - Allow the use of bigger OD firing head and redundant firing head.
  - Provide more flow area through the packer.

Surface testing

- Salt production at surface affected the stability of flow rate measurements. Amount of salt produced at surface was directly proportional to choke size. Technologies to be investigated to enable uninterrupted well production testing from salt saturated formations without risk of salt plugging in surface lines and production tubing.

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