Fluid customization, equipment optimization enable UB drilling of high-H_2S horizontal wells

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UNDERBALANCED drilling (UBD) has long been accepted as a viable well construction technique offering many benefits. UBD can avoid or minimize drilling issues such as lost circulation and stuck pipe. It increases rate of penetration (ROP) over conventional drilling techniques. It enables formation evaluation while drilling. It also reduces or eliminates formation damage because no fluid is lost to the formation in most cases, resulting in higher productivity wells, and possibly increases reserves.

More recent techniques in evaluating candidates for underbalanced drilling have removed much of the uncertainty over whether a well will benefit from UBD, and new equipment and fluids have improved the safety, efficiency and productivity of wells drilled or completed underbalanced.

The industry has learned through experience and testing that the simple fact of being underbalanced does not guarantee the prevention of formation damage, leading to advances in engineering design and fluids systems. Challenges remain, however, in equipment, engineering and fluids technology, and these challenges must be addressed in order to demonstrate the benefits of underbalanced drilling and to create a better return for operators.

Each major UBD project possesses a learning curve and may require some optimization in equipment and procedures to fully optimize the technique for a specific reservoir. An underbalanced drilling program undertaken by **Saudi Aramco** in the Ghawar Field is one example. After an initial evaluation of underbalanced drilling for water injector wells, Aramco drilled three oil wells in the Uthmaniyah area of the Ghawar Field under challenging conditions.

GHAWAR CHALLENGES

Saudi Aramco drills wells in the Ghawar Field to maintain oil production from the Arab-D reservoir. The Arab-D formation is a fractured, oil-bearing carbonate reservoir. Hydrocarbon recovery has been traditionally optimized through the drilling and completion of overbalanced vertical and deviated wellbores. Some of these operations have been complicated by drilling-related problems. Traditionally, these wells are drilled with mud weight (MW) that exceeds the reservoir pressure by approximately 200 psi. The overbalance pressure results in mud filtrate invasion and drilled solids penetration into the carbonate formation. Consequently, this results in formation damage requiring extensive acid stimulation to bring back the productivity of these wells. Further, drill string sticking and lost circulation results in excessive non-productive time (NPT).

Saudi Aramco had identified the minimization of drilling fluid losses into the reservoir, formation damage and fewer operational problems as key well objectives. Underbalanced drilling was considered an enabling technology that could potentially help achieve these objectives.

THE UB PROGRAM

The geology of the area drilled, shown in Figure 1, is a carbonate/dolomite with varying degrees of porosity. The lenses in Zone 2A are the most prolific zones with the highest porosity. Zone 2B is a tighter zone and usually exhibits lower porosity values. Zone 3 is the densest zone with the lowest porosity. The wells drilled cut a path through all three zones.

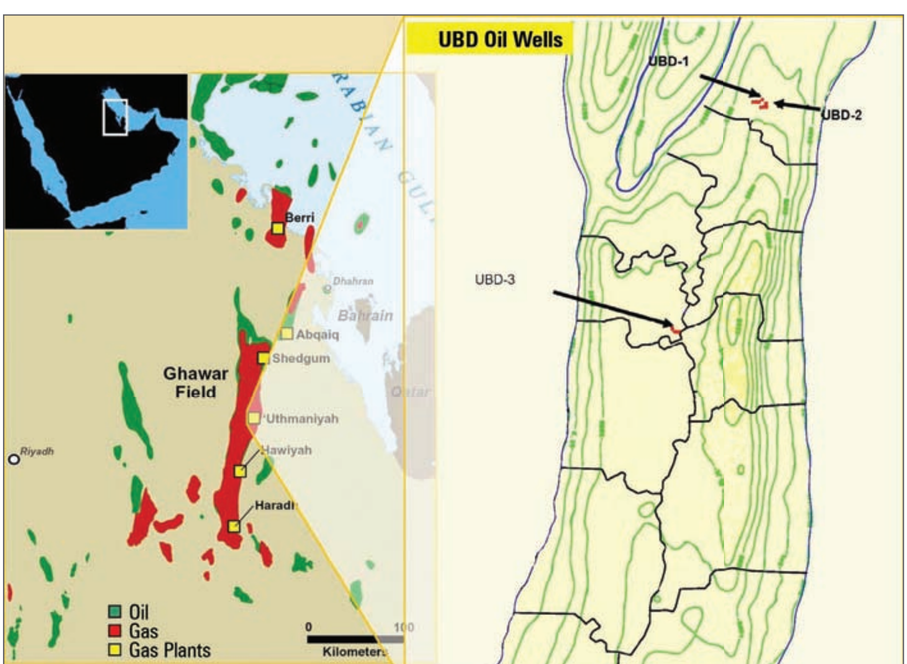

Figure 1: Saudi Aramco drilled three oil-producing pilot wells in the Uthmaniyah area of the Ghawar Field using underbalanced drilling techniques. The area is a carbonate/dolomite with varying degrees of porosity.

The UBD concept was a simple one: Apply a flow-drilling technique based on the prevailing reservoir pressure using diesel as the circulating medium and apply surface choke pressure to create the amount of underbalance required while drilling horizontally through the Arab formations.

UBD oil well pilot project

A three-well UBD pilot project to deliver single lateral-horizontal oil-producing wells was undertaken by the UBD Team to be completed by the first quarter 2006. The reservoir objectives were:

- Assess extent of reduction of invasive formation damage across the UBD-penetrated reservoir section.
- Achieve oil production along the entire length of the horizontal wellbore.
- Deliver a single-lateral horizontal well requiring minimum pressure draw-down along the horizontal section to produce desired oil target

rate, thus reducing water coning and prolonging dry oil production from the well.

- Optimize oil inflow into the horizontal wellbore to promote optimum reservoir drainage/sweep and oil recovery.
- Avoid the need for well stimulation.
- Characterize and test the reservoir while drilling.

UBD-1 PROGRAM, DESIGN

UBD engineering design

Multiphase flow behavior within the wellbore during underbalanced drilling is very complex. The response of downhole conditions to changes in various flow parameters must be characterized prior to the commencement of underbalanced drilling operations in order to maximize the chances of success. Due to the pressure gradient of the Arab-D, flow-drilling was deemed as a suitable UBD technique for application on the three planned oil producers.

The typical well plan for the project is as outlined in Figure 2. On all three wells, a 7-in. liner was set within the 9 5/8-in.

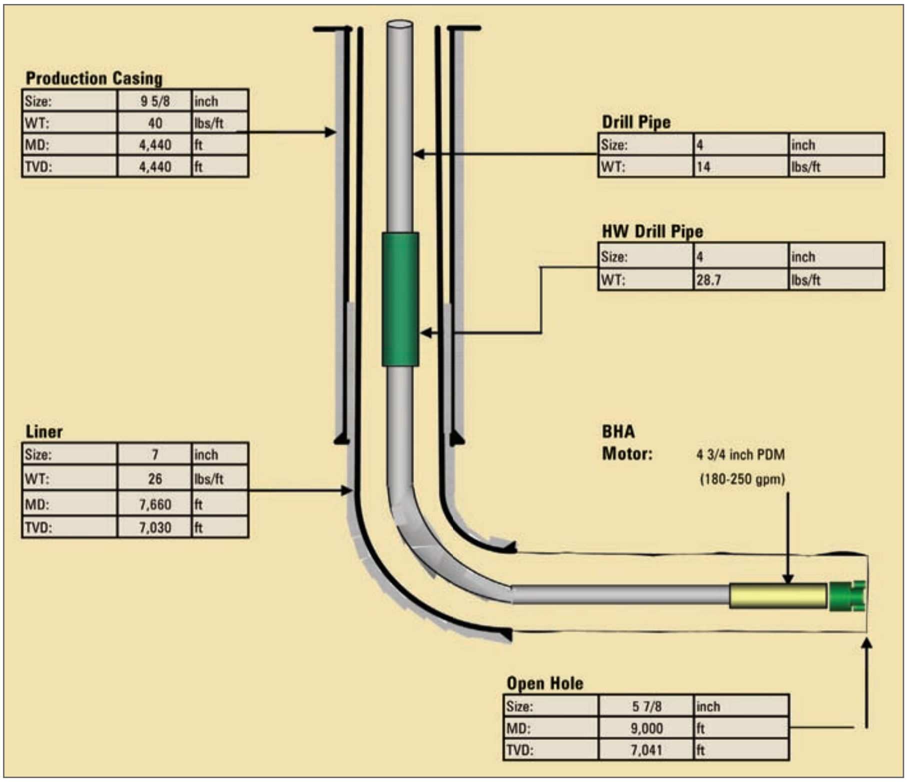

Figure 2 outlines the typical well plan for the UBD project, with a 7-in. liner set within a 9 5/8-in. casing on all three wells. A 7-in. tieback is then run to surface to provide a single bore conduit for fluid returns while drilling this section. The primary objective is to ensure good hole cleaning.

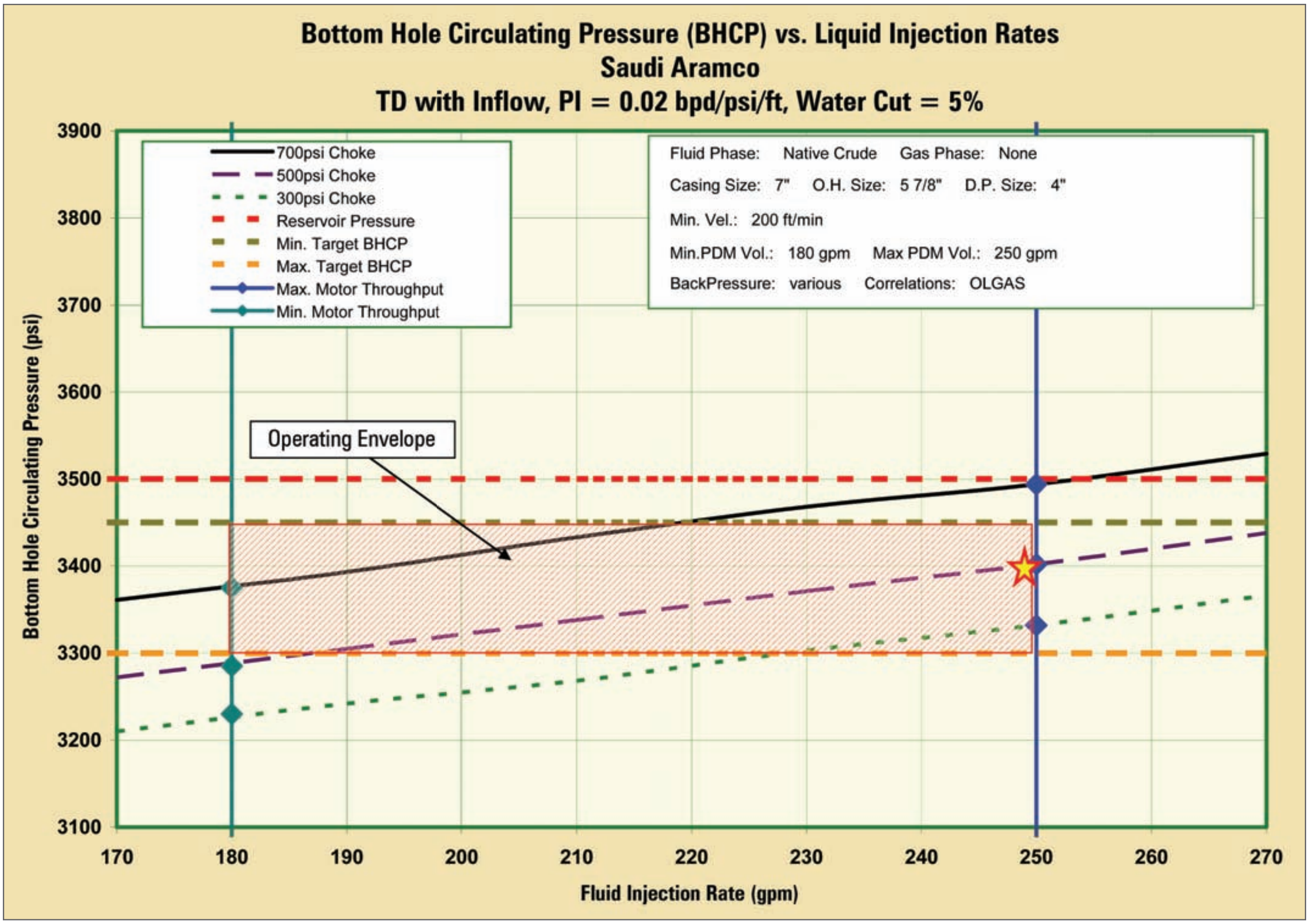

Figure 3 (above): The shaded area shows the operating envelope on a plot of bottom-hole circulating pressures vs fluid injection rates at varying choke pressures. Table 1 (below) lists design parameters used to generate the operating envelope. Establishing clear operating envelopes allowed the underbalanced wells to be drilled successfully.

DESIGN PARAMETERS	
Parameter	**Description**
Drilling Fluid	Diesel/Native Crude Oil (0.86 SG)
Injection Rates	170 - 270 gpm Crude Oil
Injection Pressure	2,200 - 2,800 psi
Wellhead Pressure	500 psi
Estimated Reservoir Pressure	3,500 psi @ the heel and 3,600 @ the toe
Min Drawdown @ BHCP	3,450 psi; Max Drawdown @ BHCP = 3,300 psi
Motor	Min Motor Q = 180 gpm; Max Motor Q = 250 gpm
Min Horizontal Velocity	200 ft/min Min Vertical Velocity = 150 ft/min

casing. A 7-in. tieback was then run to surface to provide a single bore conduit for fluid returns while drilling this section. The primary objective of running the 7-in. tieback was to ensure good hole cleaning, which would eliminate the need to pump high viscous sweeps in the absence of a tieback string.

__UBD operational envelope__

Figure 3 shows a plot of the bottom-hole circulating pressures versus fluid injection rates at varying choke pressures. The operating envelope that was established was based on the respective wellbore configuration. The operating envelope is shown within the shaded area in Figure 3. The star highlights the optimum combination of both injection rates and choke pressure to achieve the desired bottomhole pressure.

In order to manage hole cleaning and inflow, additional constraints must be addressed within the operating envelope. For example, a maximum draw-down at the bit of 200 psi was designed to minimize the oil influx and to account for any upset in the flow regime while making connections. The 200-psi underbalance was incorporated into the design to ensure underbalanced conditions in the well were maintained at all times. Typically, injection flow rates are constrained by the minimum and maximum downhole motor equivalent flow rates, which were between 180 gpm and 250 gpm, respectively, on these wells. The downhole conditions are also constrained by the ability of the circulating system to effectively achieve an underbalanced state while providing adequate hole cleaning.

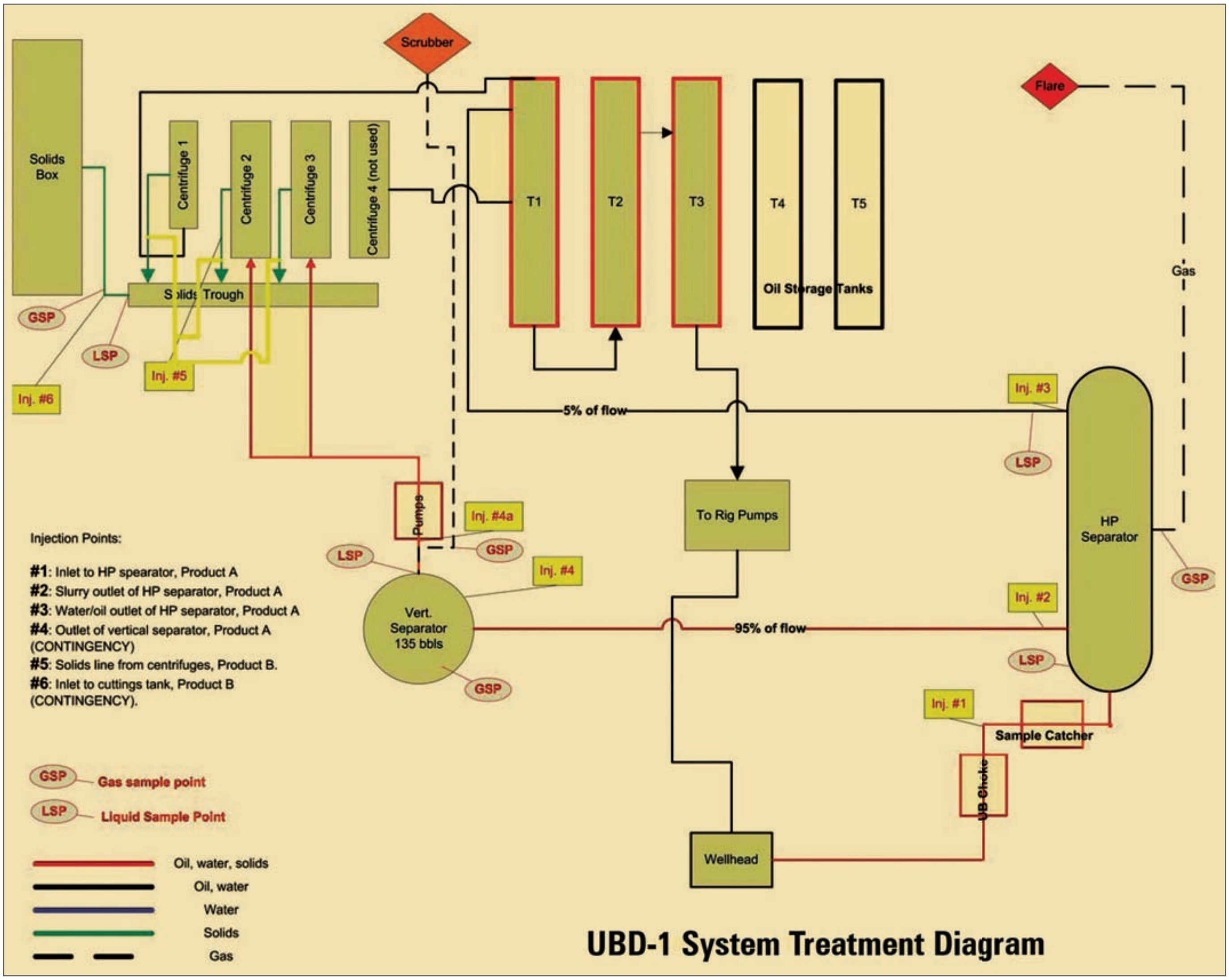

Figure 4: A hazard operability study (HAZOP) and a hazard identification (HAZID) were performed during the planning stages. The initial process was designed and based on the expected well characteristics outlined in Table 1.

The design parameters that were used to generate the operational envelope are listed in Table 1. Performing the initial detailed engineering study and establishing clear operating envelopes allowed the three wells to be successfully drilled underbalanced while maintaining hole cleaning objectives and ensuring that equipment constraints were adequately maintained.

Initial process planning

During the planning stages of the oil project, both a hazard operability study (HAZOP) and hazard identification (HAZID), or risk analysis, were performed on the entire process as outlined in Figure 4. The initial process was designed and based on the expected well characteristics outlined in Table 1. From the results of both studies and based on the expected inflow rates and H_2S percentage, it was deemed appropriate to use the H_2S scavenger as a barrier for an open-circulating system. Traditionally, in underbalanced environments, the use of a closed-loop circulating system is required with a H_2S content over 10 ppm in the gas phase. Within a closed sour circulating system, all residual gas must be either flared or vented through atmospheric scrubbers to eliminate H_2S prior to release to atmosphere.

The purpose of implementing an open-circulating system was to enable the use of centrifuges on the three-well trial in order to establish a means of solid control on multilateral UBD sour well projects with horizontal lengths of up to 6,000 ft. Although well lengths on this project would not exceed 1,800 ft, it was deemed critical for the implementation of the underbalanced technology to have a form of solids handling for extended-reach underbalanced laterals. Centrifuges were chosen due to their high capacity of removing fines that are associated with carbonate reservoirs. In order to provide a means of solid handling in a sour environment, both oil- and water-based H_2S scavengers were required to ensure that no H_2S was released to the atmosphere.

FLUID TREATMENT

Because any produced gas from UBD-1 was estimated to contain 700 ppm or higher of H_2S, it was necessary to treat the produced fluids with an H_2S scavenger in order to remove H_2S prior to the centrifuge system so that the separated cuttings did not contain H_2S. Free H_2S in the solids system could pose health issues for operational personnel.

Two high-performance H_2S scavengers, Product A and Product B, were recommended for the circulating system. Product A is an oil-soluble scavenger that rapidly removes H_2S from the hydrocarbon stream and converts it

	GAS	LIQUID		
Elapsed Time (hours)	Separator Outlet	Separator Inlet	Centrifuge Outlet	Return Fluid
2	1200			
3	2000			
4	>4000			
5		120	25	
6				1.5
9		80	19.2	
9.5	>4000			
10.5	>4000			
11		77	36	
13		88	29	
15.5		90	71	
16.5	>4000			
17.5		210	80	

Table 2: H_2S concentrations measured at various points in the drilling of UBD-1 shows that at several times, not all of the H_2S was scavenged along the fluid path.

into an oil-soluble but nonhazardous product, which then becomes part of the circulating system. Once converted into the nonhazardous product, the H_2S no longer can revert to its gaseous form. This product was intended to be the primary scavenger, since the program was designed for a hydrocarbon circulating system. Product B is a water-soluble scavenger that rapidly removes any H_2S from any aqueous phase in the system. It was planned for use in the cuttings washing stage following the centrifuge, and could be used as a contingency should an influx of produced water occur in the main circulating system.

The primary principles of the treatment system design were:

- Maintain a goal of no exposure of personnel or equipment to free H_2S.
- Set up several primary injection points and several contingency or auxiliary injection points in order to handle any intrusion of H_2S into the system at any point along the process flow.

Product A was injected into several points in the process, with Product B injected only in the solids discharge section of the centrifuge system.

H_2S concentrations were measured in the separator outlet (gas phase) at intervals. The on-site mud engineer also made measurements on liquid samples taken at the inlet to the separator, the outlet from the centrifuges, and the fluid returned to the rig and pumped down the drillstring.

UBD-1 RESULTS

Drilling results

UBD-1 was successfully drilled to a measured depth (MD) of 8,702 ft, with a lateral section of 1,102 ft, in 25.5 hrs. During the 16 hrs of on-bottom drilling, the operation averaged 69 ft/hr, with an instantaneous rate of 150 ft/hr at several points. No lost-time incidents were reported, and all surface and downhole systems worked adequately. Excess produced oil not needed for the circulating system was exported to the gas oil separation plant (GOSP). No produced water was recorded at any point. There were three H_2S alarm musters during the operation, attributed to changes in wind direction that brought vented gas from the storage tanks or centrifuges back to the rig area.

H_2S treatment results

The H_2S concentrations at various points in the process were measured and are shown in Table 2. From the presence of H_2S in the produced oil in the storage tanks and vapor space above the tanks, it was clear that, at several times during the drilling process, not all of the H_2S introduced to the system were scavenged along the flow path of the fluid. After the initial alarm, the treatment was effective; over a period of more than 9 hrs, the drilling operation proceeded without incident and without H_2S release. Two additional H_2S alarms occurred before the operation was completed.

Because H_2S is not very soluble in hydrocarbon systems, it tends to separate into the gas phase. Normally, the concentration of H_2S in a hydrocarbon phase is 3% to 5% of the concentration present in the gas phase. Thus, for a nominal concentration of H_2S in the gas phase of 700 ppm, it is expected that there will be 21-35 ppm H_2S in the liquid phase. This assumes reasonable gas separation. For a gas phase concentration of 4,000 ppm (the minimum amount measured during most of the operation), the concentration of H_2S that likely was present in the oil phase was 120-200 ppm. This roughly corresponds to the measurements taken on the liquid phases.

Product A and Product B scavenge H_2S at a normal ratio of 5-10 parts scavenger to each part of H_2S. For a liquid phase concentration of 35 ppm (the maximum expected), the scavenger is treated at 175-350 ppm. For an H_2S concentration in the liquid of 200 ppm, a scavenger injection rate of 1,000-2,000 ppm would be needed.

From the injection rates used during the operation, the scavenger injection should have been more than sufficient to scavenge liquid-phase H_2S from the system. The average concentration of Product A injected was 1,517 ppm, in some cases higher. Therefore, it is clear that there was residual gas breakout throughout the system that exceeded the H_2S scavengers' capability to remove all H_2S present. This required a reassessment of the surface equipment design.

OPTIMIZATION – UBD-2

Process modification

With the higher-than-expected flow rates and H_2S content seen after the first well, a revised process was required because of the release of H_2S at and around the centrifuge area. In order to prevent any release of H_2S to atmosphere, the system was modified to incorporate a vertical surge vessel rated for 150 psi to both increase the retention time of the process and to assist with gas breakout prior to the fluid reaching the centrifuges.

The high Reid Vapor Pressure (RVP) of the reservoir fluid made it critical that

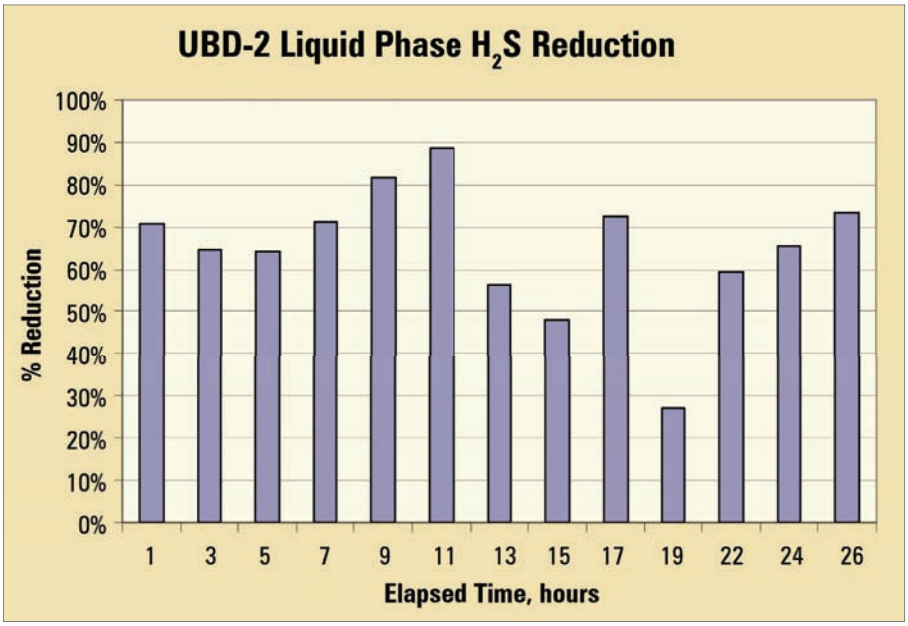

Figure 5 shows the reduction in H_2S concentration in the circulating liquid between the inlet to the separator and the fluid return to the rig floor. Over the entire interval, H_2S reduction averaged 65% — lower than was anticipated.

the overall pressure in the horizontal and surge vessels be reduced to as low as possible to aid in gas breakout prior to the centrifuging process. Doing this would allow the majority of the gas to be removed in both separation devices. The surge vessel was installed upstream of the centrifuges with an average operating pressure of approximately 5 to 10 psi. Running the vessel at a reduced pressure allowed the residual gas to be taken to flare without additional risk.

With the high influx and gas-oil ratio (GOR) on the well and the lower-than-expected retention time of the process, minor H_2S releases were evident throughout the drilling of the well.

Fluid treatment modifications

While it was concluded that the products worked effectively in scavenging H_2S, modification of the treatment plan was needed to address possible spikes in H_2S or periods of residual gas breakout downstream of the separator. It was decided to keep the scavenger injection point upstream of the separator but to minimize or eliminate its use. Increased injection capacity was added downstream of the separator only. Since nearly all of the gas is separated and sent to flare from the separator, most of the H_2S will be removed at this point, and scavenging upstream of the separator would likely not be cost-effective.

Additional injection pump capacity was added for UBD-2 so that any large influxes of H_2S could be handled. An increased monitoring program was implemented for better determination of H_2S levels at critical system points. The treatment system was designed for a higher H_2S level than anticipated, and plans were made to adjust scavenger injection rates initially, once the H_2S concentrations were measured at the start of UBD-2. Product A was again the primary scavenger, with Product B used in the water system in the centrifuge area to wash the cuttings. A commodity scavenger, zinc-based, was made available for use in the cuttings tank to remove any residual sour gas trapped on the cuttings.

It was also decided to pre-treat the diesel circulating fluid with the scavenger so that it would have good scavenging capacity when the producing formation was reached. This would provide a buffer capacity of scavenger should an initial high surge of gas be generated early in the drilling operation.

UBD-2 RESULTS

Drilling results

UBD-2 was successfully drilled to a measured depth of 9,500 ft (7,121 ft TVD), with a lateral section of 1,443 ft, in 24.7 hrs. On-bottom drilling rates of penetration averaged 58 ft/hr, with an instantaneous rate of 135 ft/hr at several points. No lost-time incidents were reported, and all surface and downhole systems worked adequately. Underbalanced conditions were maintained and continuously monitored through the drilling of the reservoir section of this well. Excess produced oil not needed for the circulating system was exported to the GOSP. No produced water was recorded during the drilling operation.

H_2S treatment results

The fluid circulating system treatment showed the benefits of the modifications made after the first well. The pre-treatment of the diesel system successfully removed much of the initial H_2S as the producing zone was reached and initial gas surge reached the surface. The added injection capacity of the scavenging system was able to be used as the production levels increased, and the injection points selected were deemed appropriate for the operation.

Figure 5 shows the reduction in H_2S concentration in the circulating liquid between the inlet to the separator and the fluid return to the rig floor. The percentage reduction increased steadily for the first 12 hrs of operation to just under 90%, as some excess scavenging capacity in the circulating fluid was slowly built up, then declined at several points after that. Over the entire interval, the H_2S reduction in the liquid averaged 65%, which is lower than anticipated and below the norm for this product and

	LIQUID	GAS	
Elapsed Time (hours)	Separator Inlet	Return Field	Separator Inlet
0			2
1	58	17	
2			2
3	62	22	2
5	50	18	3000
6			6000
7	150	43	6000
8			14000
9	375	68	
10			6000
11	225	26	
12			7000
13	240	105	
14			9000
15	112	58	
16			14000
17	138	38	
18			14000
19	77	53	13000
20			14000
22	143	58	14000
23			13000
24	140	48	
25			12000
26	138	37	13000
27			13000

Table 3: H_2S levels for UBD-2, like in UBD-1, indicate that some residual gas breakout from the liquid occurred and scavenger effectiveness was reduced.

application, but it was clear that the scavenger treatment was largely effective.

H_2S levels for UBD-2 are contained in Table 3. The levels in the gas slowly increased as the top of the producing formation was reached until a level of 14,000 ppm was measured 16 hrs into the operation. At this point, an H_2S alarm occurred near the centrifuge outlet, possibly caused by entrained gas on the cuttings.

Product A injection rates were adjusted according to the incoming gas and liquid H_2S levels, reaching a maximum of approximately 6,000 ppm at one point during high gas production rates but averaging just under 1,900 ppm for the overall drilling time.

As on UBD-1, there were indications that some residual gas breakout from the liquid was occurring. The variation in the reduction in H_2S in the liquid system during the second half of the drilling program indicated gas was breaking out of the liquid at several points in the system, reducing the effectiveness of the scavenger. An increase in the separator pressure for operational reasons also may have contributed to some residual gas breakout after the primary separator.

Scrubber performance

The atmospheric scrubbers used to remove any trace of H_2S from the vents of the fluid storage tanks contained either aqueous ammonia or Product B as the scavenging medium. Both worked well within their recommended operating ranges, but there were indications that these could be improved for the third well.

Conventional scrubbers in an underbalanced environment rely on a fluid level above the gas outlet and a scrubbing agent to remove any residual H_2S from the gas within the scrubber itself. These scrubbers inherently provide backpressure due to the fact that the gas outlet is submerged within the fluid itself. This fluid level could exert a small pressure on the tanks. This pressure increase, though very low, could cause lifting of the pressure vacuum breakers (set at 16-oz pressure and 4-oz vacuum) and a possible H_2S release. A second H_2S alarm during the drilling operation may have been caused by this phenomenon, since the wind direction at the time was from the scrubber outlets directly toward the H_2S sensors near the tank farm.

OPTIMIZATION – UBD-3

Process modification

With the learnings from the second well, the need to prevent further H_2S releases in conjunction with a varying baseline for inflow, it was deemed necessary to revert back to a closed-loop system for the third and final well of the trial. This was easily accomplished by removing the centrifuges, surge tank and providing two high-rate backpressure-less scrubbers. The concept was to run the four-phase separator at a lower pressure and a higher liquid volume to aid in the separation process prior to the fluid moving on to the stock tanks. The scrubbers were rigged up on the vent line off the top of the stock tanks and the oil cascaded through five 500-bbl tanks prior to the fluid either being exported or re-injected downhole. Although atmospheric scrubbers were run on the previous two wells, it was required due to the gas breakout observed in the atmospheric tanks to complete calculations to determine the optimal sizing of these scrubbers.

Considering the above, it was deemed appropriate to move to a larger scrubber that exerts no backpressure on the tanks themselves and has the propensity to handle large volumes of gas. The plan was to contain and flare as much gas as possible prior to the fluid moving to atmospheric tanks. However, with the high RVP of the fluid, it was impossible to remove it all. Cold vents were taken to a safe area where H_2S and LEL monitors were set up to monitor any release.

Fluid treatment modifications

The treatment and monitoring program used on UBD-2 was considered effective for the operation. Therefore, based on experience from the first two wells, no major changes were planned for UBD-3. A logistics delay in securing additional quantities of Product A, however, resulted in the need to change scavenger products for the main circulating system. Two additional products, Product C and Product D, were recommended for use on UBD-3 instead of Product A. Product C was a primary H_2S scavenger, and Product D was a dispersant. Product D was designed to enhance the solubility characteristics of Product C, and the two were to be used together in a 1.5:1 ratio of Product C to Product D.

Product B, the water-soluble scavenger used in the scrubbers and wash water on previous wells, was planned for the zero-backpressure scrubbers scheduled for UBD-3. This product had been effective on the first two wells and was preferred over aqueous ammonia for its favorable toxicity and personnel exposure profile.

The equipment and fluid treatment design for the third well is shown in Figure 6. The removal of the vertical separator and centrifuges resulted in fewer injection points than the previous wells.

UBD-3 RESULTS

Drilling results

UBD-3 was successfully drilled to a MD of 9,067 ft (6,857 ft TVD), with a lateral section of 1,725 ft, in 26.5 hrs. On-bottom drilling average ROP was 86 ft/hr. No QHSE incidents were reported, and all surface and downhole systems worked adequately. Underbalanced conditions were maintained and continuously monitored throughout the drilling of the reservoir section of this well. Excess produced oil not needed for the circulating system was exported to the GOSP.

No produced water was recorded during any point in the drilling operation. Additionally, this was the first successful run for a downhole isolation valve within Saudi Aramco. The use of the downhole valve eliminated the need to kill the well and built considerable confidence for running the valve in the future for underbalanced applications.

H_2S treatment results

By revising the overall process, utilizing both the oil-soluble scavengers and the high-rate scrubbers proved effective in preventing any H_2S release to atmosphere on the third well.

Table 4 shows the measured H_2S concentrations in the liquid at several points in the circulating system. The H_2S concentrations in the gas stream on this well reached 15,000 ppm within an hour of operation and maintained this level for the duration of drilling, and so are not shown. The average over the 26 hrs of drilling was 14,650 ppm.

H_2S concentrations in the circulating system were slightly lower than the previous two wells, despite the marginally higher gas levels, indicating an increased effectiveness of the separation process. H_2S concentrations in the separator inlet slowly rose, reaching 240 ppm at one point, before gradually declining

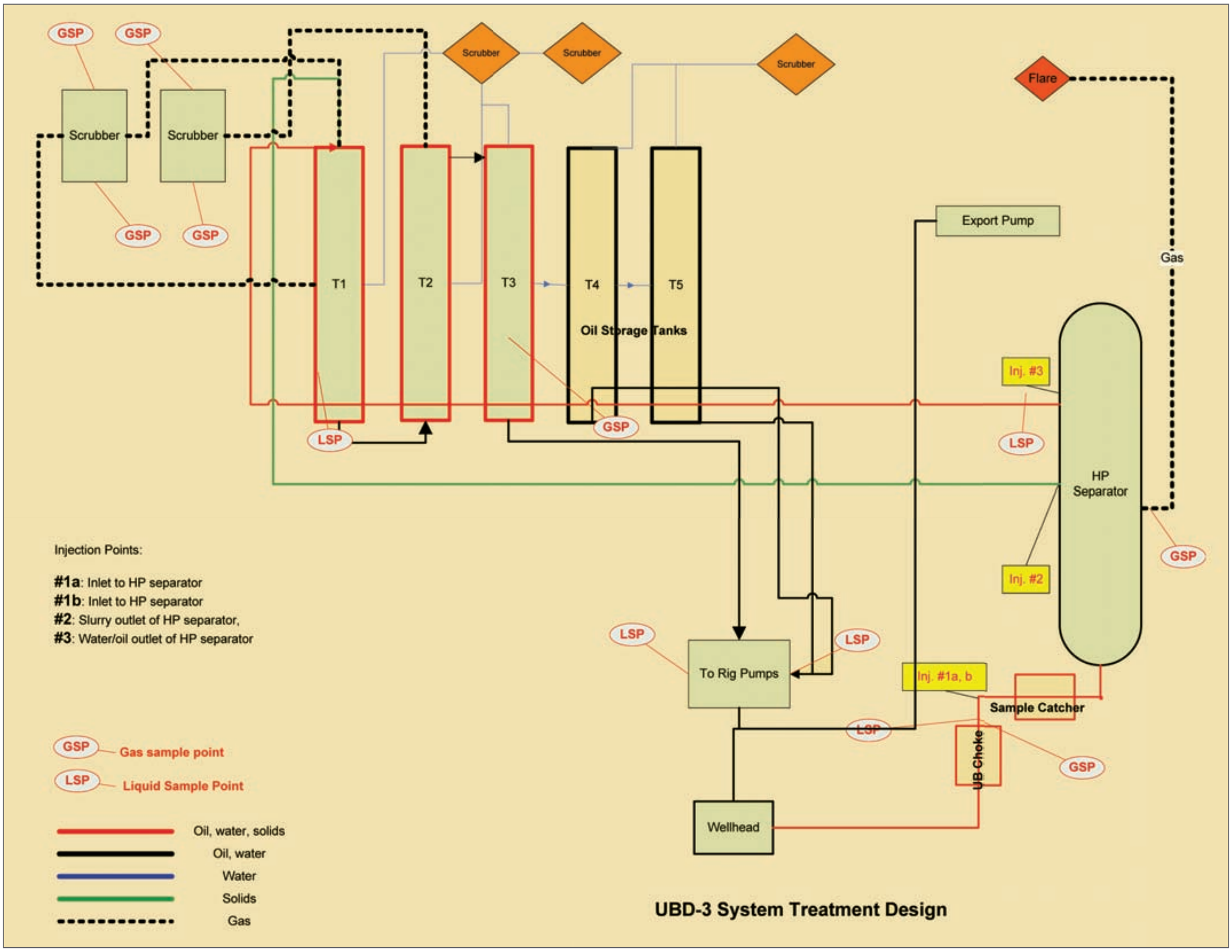

Figure 6: In the third underbalanced well of the pilot program, the vertical separator and centrifuges were removed, resulting in fewer injection points than the previous wells.

to 20-40 ppm for the second half of the drilling operation. The two scavenger products worked very effectively, with no operational concerns, and no H_2S releases occurred.

Scrubber performance
The installation of the zero-backpressure scrubbers showed a significant improvement in the removal of small amounts of H_2S coming from the storage tank vents. The scrubbers showed good throughput with no backpressure issues, and Product B's scavenging performance in the scrubbers was excellent.

The incoming H_2S concentration increased from 4,000 ppm to over 16,000 ppm, but the outlet concentration was essentially zero for over 15 hrs, a very good performance in a scrubber of this type. There were indications that Product B had a higher capacity (longer life in the scrubber) than the aqueous ammonia previously used.

UBD PROJECT RESULTS

Saudi Aramco safely and successfully implemented underbalanced drilling operation on the three pilot wells. The entire UBD operation was completed trouble-free, with all surface and downhole equipment operating as expected. The handling of sour fluid on surface was done in an environmentally safe manner. The excess produced fluid was cleaned and shipped to the nearby production facility without problems. The UBD Team worked seamlessly at the office and on the field level to achieve a milestone in Saudi Aramco history.

Production Results
Several well rate tests have been conducted on the three wells since their production start-up; downhole production logging surveys were also completed on the three subject wells.

UBD-1 and UBD-2 have superior PI values (371 bbl/d/psi and 110 bbl/d/psi, respectively) compared with nearby offsetting conventionally drilled wells. Production logs for the two UBD wells show fluid entry along the entire horizontal sections for each well. Measured pressure draw-down for UBD-1 and UBD-2 was 19 and 41 psi, respectively. However, the recorded rising water production from UBD-1 and UBD-2, notwithstanding good PI values, low pressure draw-down and uniform production inflow profiles, is affected by thin oil column (about 30 ft) at the two well locations.

The third and last well in this pilot program, UBD-3 was drilled underbalanced in April 2006. PI values and pressure draw-down of 114 bbl/d/psi and 62 psi is comparable with nearby offsetting conventionally drilled wells. UBD-3 well inflow production profile shows that the well produces along its entire horizontal length.

In summary, underbalanced drilling of three horizontal oil producing wells in Uthmaniyah Arab-D highly pressured good-quality reservoir achieved the following:

- Equivalent or higher PI values compared with conventionally drilled horizontal oil producers.
- Uniform inflow profile along the entire horizontal section of the UBD wells.
- Lower pressure draw-downs during production.

CONCLUSIONS

This three-well pilot project demonstrated that underbalanced drilling is both practical and beneficial even for highly productive and highly pressured wells in sour environments. The engineering planning for the project considered most possible scenarios and resulted in smooth operations and rapid drilling of the horizontal sections. The ability to modify the equipment design and adapt to changing conditions proved invaluable in maintaining operational safety and improving the fluid handling performance over the three wells.

The use of the H_2S scavengers in both the hydrocarbon circulating system and the scrubbers allowed these wells to be drilled while being produced without any major exposure hazards to personnel or equipment. Saudi Aramco was therefore able to drill with a non-damaging technique, evaluate the productive zones while drilling, and offset the cost of the operation by producing salable crude oil as the well was being drilled.

Specific lessons gained from the project:

- A closed-loop circulating system is an accepted method of containing produced fluids and gases and can be used even in highly productive wells.
- The use of solids control equipment is a viable option in extended horizontal sections that may benefit from it but requires additional operational practice to avoid H_2S releases from open points in the system.
- Hydrogen sulfide scavengers are an enabling technology in wells of this type and can be used effectively to minimize releases from exposed fluid.
- Separation practice is important to gas removal from the circulating fluid, particularly high Reid Vapor Pressure systems such as these. The combination of pressure management in the vessels and proper flow design is important in reducing hazards and allowing efficient drilling.

	LIQUID H_2S CONCENTRATIONS		
Time	Separator Inlet	Tank Farm	Return Field
1			
3	57	10	2.4
5	90	19.2	9
7	50	10	3
9	57	10	2
11	170	9	10
13	100	5	9
15	240	8	5
17	140	9	8
19	20	5	9
21	30	8	4
23	40	4	8
25	24	6	3
27	29	9	5
29	22	6	2
31	50	12	6
Avg.	74.6	8.7	5.7

Table 4: H_2S concentrations in the liquid in UBD-3 were slightly lower despite the marginally higher gas levels, indicating a more effective separation process.

RECOMMENDATIONS FOR FUTURE WELLS

Keeping in mind the initial objective to drill long-reach laterals in a sour underbalanced environment where solids handling is a requirement, further engineering studies were conducted to determine a fit-for-purpose process, given the well characteristics on the three pilot wells. A simulation study was conducted to determine the following:

- Optimal process configuration with the expected flow rates, gas characteristics and H_2S percentage.
- Determine residual gas break throughout the process and reduce the RVP to approximately 10 psia.
- Provide a fit-for-purpose proposal for drilling high-PI wells in a sour underbalanced environment.

In order to prevent H_2S release to atmosphere, it was deemed critical to reduce the RVP of the crude to less than 10 psia prior to the fluid entering the stock tanks. Studies were conducted to determine the size and optimum placement of a heater to reduce the vapor pressure of the reservoir fluid. Numerous simulations were conducted, and it was deemed feasible to modify the process slightly from the third well and install a 3 MMBTU heater prior to the fluid entering the four-phase separator. By reducing the RVP of the fluid and scavenging the H_2S with an oil-based scavenger, the process technically would be conducive to the use of centrifuges downstream of the heater.

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