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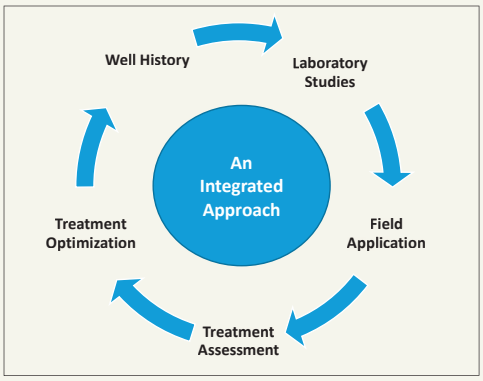

An integrated approach was applied successfully to restore/improve productivity of damaged wells by organic deposition. This included the study of well history/production data, as well as laboratory testing and analysis to identify the nature of the obstruction material, assess the potential of asphaltene deposition, and propose an optimized solvent system. The approach also included treatment execution, assessment and optimization.

On the Cover

Well-A was damaged by severe organic deposition to an extent it was observed in the wellhead.

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Contents

From Lab to Field: An Integrated Approach to Successfully Restore the Productivity of Wells Damaged with Organic Deposition

Ali A. Al-Taq, Basil M. Alfakher, Salah A. Al-Muhaish and Abdulla A. Al-Rustum

ABSTRACT

Asphaltene deposition is a major formation damage issue in production wells with asphaltene problematic oil. Asphaltene can precipitate within the reservoir or in the production tubing, resulting in partial or total loss of well productivity. This is an especially significant concern in reservoirs with a high gas-oil ratio (GOR), as more gas is present to dissolve in the oil and strip out the asphaltene. This mechanism might be responsible for production loss in several wells in Field-A that are partially or totally damaged with asphaltene precipitation.

An extensive laboratory study, including solubility tests, saturate aromatic resin asphaltene (SARA) analysis, compatibility tests and coreflood experiments, was performed to assess solvent systems to remedy asphaltene deposition. Solubility tests were conducted at reservoir temperature — 220 °F — and elevated pressures using asphaltene obtained from a bailer sample to determine the effectiveness of different solvent systems. SARA analysis was performed to assess the stability of the reservoir oil of interest. Compatibility tests and coreflood experiments at reservoir conditions were also conducted to assure solvent system compatibility with formation fluids. In addition, other factors, including the overall cost and environmental impact, were taken into account in choosing the most suitable solvent system.

The lab testing investigated a number of candidate solvent systems with high asphaltene solvency power. Some solvent systems were ruled out because they were damaging to core permeability, as indicated by results from the compatibility tests and coreflood experiments. Selected solvent systems were then used in two successful chemical treatments performed on Well-A within a time interval of more than two years; a case study of those treatments is presented. The first treatment was successful in restoring the productivity of Well-A. The second one used a more cost-effective solvent and was able to partially remove the organic deposition damage with a cost savings of 60%. In both treatments, a two-stage remediation procedure was implemented to dissolve the organic deposition in the horizontal open hole section of this well. The first stage included bullheading the solvent and allowing it to soak for 24 hours to clean out the tubing. The second stage involved injecting the solvent in the open hole section using coiled tubing (CT) with a jetting/pulsing mechanism. Results show that the wellhead pressure (WHP) increased by 40%, indicating the successful dissolving of the organic deposition and restored well productivity.

This article presents a new methodology that incorporates a variety of analytical techniques to help in choosing the most proper and cost-effective asphaltene treatment solution for a specific reservoir and for a successful field treatment.

INTRODUCTION

Organic Deposition

Organic deposition, including asphaltene and paraffin deposition, is a common problem in both the upstream and downstream oil industry. A common definition of asphaltenes is the fraction of oil that is insoluble in n-pentane or n-heptane, but soluble in benzene, toluene, ethylenbenzyene and xylene (BETX). Asphaltenes are also defined as polyaromatic condensed rings with short aliphatic chains and polar hetro-atoms (N, O and S) in functional groups such as ketones, thiophenes, pyridines and porphyrins[1]. Asphaltenes stabilized by resins exist as a colloidal dispersion in the crude oil at reservoir conditions, but often precipitate in production lines, and even in the reservoir, due to changes in composition, temperature and pressure. Asphaltene precipitation can cause severe problems in production, transportation and refining.

On the production side, asphaltene precipitation can result in partial or total loss of well productivity. Asphaltene precipitation can damage formation permeability and shift formation wettability to a more oil-wet condition, resulting in declining oil production and increasing water production. A case study from a Japanese oil field where an oil well was damaged by asphaltene precipitation confirms this decline of oil production and increase in water cut[2]. The latter was attributed to the wettability alteration to a more oil-wet condition caused by asphaltene precipitation.

Asphaltene Removal Techniques

Due to its adverse impact on production, numerous remediation methods have been developed for the removal and dissolution of asphaltene. These include mechanical removal, heat, dispersants and solvents[3-5]. Solvent-based solutions normally

include hydrocarbon-based materials. The use of organic solvents to remove organic deposits is common in the oil industry. Well treatment with solvents can also be used to stimulate oil production[4]. Typically, aromatic-based solvents such as xylene or toluene are used to remove formation damage due to organic deposits. The efficiency of aromatic solvents can be enhanced by adding small amounts of alcohols, or co-solvents. These co-solvents may be aromatic derivatives such as alkylbenzene, sulfonic acid or amine compounds[6]. Trbovich and King (1991)[5] report that a co-solvent containing an aromatic solvent system offered advantages when compared with the use of a straight aromatic. Based on lab and field data, aromatic co-solvents were found to have higher success rates, to keep wells damage free for longer periods and to offer more versatility in addressing different well damage causes than a straight aromatic solvent.

Fatah and Nasr-El-Din (2010)[3] reports on four historical cases where acid emulsified in xylene was used effectively to remove asphaltene deposition and enhance well productivity. Ibrahim and Ali (2005)[7] describes a two-pack chemical system developed to remove organic deposits in and around the wellbore and production tubing, as well as enhance the production rate. The two-pack chemical system reacts to produce in situ heat with a reaction product. The heat generated in the system dislodges and melts the organic deposits, and the reaction product acts as a dispersant and an effective surfactant. This system was applied successfully in two Malaysian offshore wells, which maintained good production rates for more than a year. Boswood and Kreh (2011)[8] presents case studies and laboratory testing results for fully miscible micellar acidizing solvents that showed superior results and were more economical compared with xylene. A solvent system made of an emulsion of a water surfactant coupled with solvents and co-solvents containing no BETX is reported to have comparable solvency power to xylene on two different asphaltene samples[9]. The reported advantages of the system are high solvency power, high flashpoint and a delay in re-deposition since the rock is left in a water-wet condition.

The current development in solvents for asphaltene removal is directed toward more environmentally friendly solvents such as naturally occurring terpenes[10]. In general, it is challenging to find solvent systems with the more favorable health, safety and environment (HSE) properties that also have the asphaltene removing power of the traditional solvents. A basic understanding of asphaltene structure and properties is essential in designing a solvent system for asphaltene dissolution. The massive impact of asphaltene deposition on oil production has led to the large number of analytical and physical property studies of asphaltenes. Frost et al. (2008)[11] describes the development of a new water-based asphaltene removal system, which was first applied in Southern Europe in 2005. Since then, the system has been optimized for broader global operations while maintaining the favorable HSE characteristics of the initial development. The system is considered unique as it provides a high flashpoint water-solvent mixture with solvency power often greater than xylene and the additional benefit of leaving the formation strongly water-wet.

Asphaltene Inhibition Techniques

Asphaltene precipitation is a persistent problem in wells that have a high tendency toward organic precipitation. Some wells even require treatments every few months to remove asphaltene scale. These frequent treatments are quite costly. It would therefore be preferable to have a means of delaying the asphaltene deposition process. Albannay et al. (2010)[12] introduces three potential methods of delaying asphaltene deposition in an offshore field in the UAE. The methods are control of the operating conditions, continuous downhole inhibitor injection and inhibitor squeeze treatments.

One way of controlling the operating conditions is to operate at higher pressures above the bubble point by reducing the choke size; however, this is not practical in high production wells where target production rates must be met. Another adjustment to operating conditions attempted in Kuwait was to coat the tubing with a thin film of epoxy resin[13]. This method showed no significant improvement, as the asphaltene also adhered to the film surface.

Continuous downhole inhibitor injection is another method of preventing asphaltene precipitation. In one study, a polymeric dispersant/inhibitor was used at cleanup dosages of 1,000 ppm to 10,000 ppm and continuous dosages of 50 ppm to 400 ppm[14]. Results showed that production was increased and maintained. For continuous treatments to be successful, however, a special completion with capillary tubes is necessary[12].

The most commonly used method for asphaltene inhibition is inhibitor squeeze treatments. Villard et al. (2016)[15] introduces an asphaltene dispersant-inhibitor system that was applied in two wells in eastern Venezuela. By applying the inhibitor system, the requirement for coil tubing (CT) intervention in the wells improved, dropping to only 60 days from over 150 days. This system was applied to relatively low production wells — 650 barrels of oil per day average rate — and it is not clear if it would work for high production wells. This is because it is more challenging to retain inhibitors in the formation rock for extended periods of time with high flow wells. Carpenter (2014)[16] reports on an inhibition system composed of alumina nanoparticles suspended in a "nanofluid" that was used on a well in Colombia. This system is deployed using an inhibitor squeeze method in areas where the alumina nanoparticles reportedly have a high affinity for the reservoir rock and will therefore be retained for a long time. The well was monitored for eight months after the treatment and was reported to be producing above the baseline with a steady pressure decline. Another study presents a novel asphaltene inhibitor that was molecularly tailored to adsorb to formation surfaces and slowly desorb in produced fluids[17]. Based on coreflood tests, the inhibitor was shown to remain in the field core sample for approx-

imately twice as long as the benchmark asphaltene inhibitor with equal performance.

In comparison with scale inhibitors, asphaltene inhibitors have a much shorter lifetime since they are harder to maintain in the reservoir rock. One study conducted by Saudi Aramco on scale inhibitor squeeze treatments to hinder calcium carbonate deposition reported an effective lifetime of more than 10 years[18]. A study of the technical and economic aspects of asphaltene inhibition compared the annual cost of squeeze treatments with the cost of solvent washes for the same duration of time[19]. The study concluded that the economics were dependent on the reservoir pressure, and therefore, the production rate.

EXPERIMENTAL STUDIES

As described below, the extensive laboratory study of candidate solvent systems to remedy asphaltene deposition using crude oil samples included saturate aromatic resin asphaltene (SARA) analysis, solubility tests, dispersant tests, and coreflood experiments.

SARA Analysis

Asphaltene content was measured using the American Standard Test Method (ASTM) D2007-80. The ASTM recommended procedure for separating asphaltenes from crude oil was used to determine asphaltene content in the organic phase of the collected samples. An equivalent of 40 times of n-pentane was added to the oil volume, and the mixture was aged and filtered as described in ASTM D2007-80. The asphaltene content was then calculated by dividing the weight of obtained asphaltene by the weight of the oil.

SARA content for reservoir oil and for the organic phase of the sludge samples was measured using middle pressure liquid chromatography[20].

Solubility Test Procedure

A gravimetric method was used to determine the solubility of organic deposits, as received, in different solvents. The solubility tests were performed at 1:10 (W/V) sample-to-solvent ratio. The tests were conducted at different temperatures, including the reservoir temperature of 220 °F, and monitored as a function of soaking time. The mixture of soaked organic deposits and solvent was filtered through 0.45 µm filter papers. The glass bottles used in the test were then rinsed with the same amount of solvent to transfer undissolved asphaltene/organic deposit into the filter paper. Finally, the solubility percent was calculated using the following equation:

$$\text{Solubility (\%)} = \frac{\text{original weight (g) - residual weight (g)}}{\text{original weight of organic deposit (g)}} \times 100 \quad (1)$$

Asphaltene Dispersant Test

The asphaltene dispersant test (ADT) is considered to be a quick and simple method to examine deposition and inhibitor/dispersant performance. It can also be used to determine the minimum inhibitor concentration, and therefore, the return lifetime of chemical squeeze treatments. N-heptane, n-pentane or hexane could be used in this test[21]. In our ADT, we used both n-pentane and n-heptane. The procedure used in the ADT in this study is outlined as follows:

- Inject X mL of inhibitor solution into a 100 mL graduated test tube.
- Add a known volume, 1 mL, of Well-A dead crude oil to the test tube and mix well.
- Add Y mL of n-pentane to a 100 mL assay and mix well.
- Incubate for 3 hours at 86 °F.
- Record the volume of basal deposits.
- Calculate inhibition (%) vs. inhibitor concentration (ppm) vs. blank, Eqn. 2:

$$\text{Inhibition (\%)} = \frac{\text{volume of ppt for blank (mL) - volume of ppt for x ppm of inhibitor (mL)}}{\text{volume of ppt for blank (mL)}} \times 100 \quad (2)$$

where *ppt* refers to asphaltene precipitate measured in mL.

Coreflood Tests Procedure

Coreflood experiments were performed in a linear mode at reservoir temperature and pressure. The main steps involved in the coreflood test procedure were as follows:

1. Evacuate the core sample of air and saturate with 7 wt% NaCl brine.
2. Load the core sample in the core holder.
3. Apply 3,000 psi confining stress and 500 psi back pressure.
4. Elevate the oven temperature to 220 °F.
5. Inject 7 wt% NaCl brine water at a constant rate while monitoring the differential pressure and elapsed time.
6. Continue with the brine injection until a stable differential pressure is obtained.
7. Calculate the core sample's specific permeability to 7 wt% NaCl brine.
8. Inject the solvent system at a constant rate while monitoring the differential pressure and elapsed time.
9. Inject 7 wt% NaCl brine at a constant rate while monitoring the pressure.
10. Calculate the initial and the final core permeability to 7 wt% NaCl brine using Darcy's law:

$$K = (245\ Q \times \mu_f \times Ls)/(As \times \Delta P) \quad (3)$$

where:

K = permeability (mD)
Q = fluid flow rate (cm^3/min)

μ_f = fluid viscosity (cP)
L_s = core plug length (cm)
As = core plug cross section (cm^2)
ΔP = pressure drop (psi)

The reduction in permeability was calculated as:

$$\text{Reduction in K} = \frac{K_i - K_f}{K_i} * 100 \quad (4)$$

where K_i = the initial brine permeability and K_f = the final brine permeability.

RESULTS AND DISCUSSIONS

This study took an integrated approach to the problem of asphaltene deposition. This included the study of well history and production data, as well as laboratory testing and analysis to identify the nature of the obstruction material, assess the potential for asphaltene deposition to occur and propose an optimized solvent system. The approach also included treatment execution, assessment and optimization. This is illustrated graphically in Fig. 1. These processes were implemented in two main repetitive cycles.

First Cycle

This section discusses the history, mechanism of asphaltene precipitation, laboratory tests, first treatment execution and evaluation of Well-A.

Well History and Production Data of Well-A. Production data is key when studying organic deposition problems. It has been observed that rapid production declines are often due to organic deposition either near the wellbore zone or on the formation face[22]. Also, acid jobs can potentially cause asphaltene sludge, resulting in production problems[23].

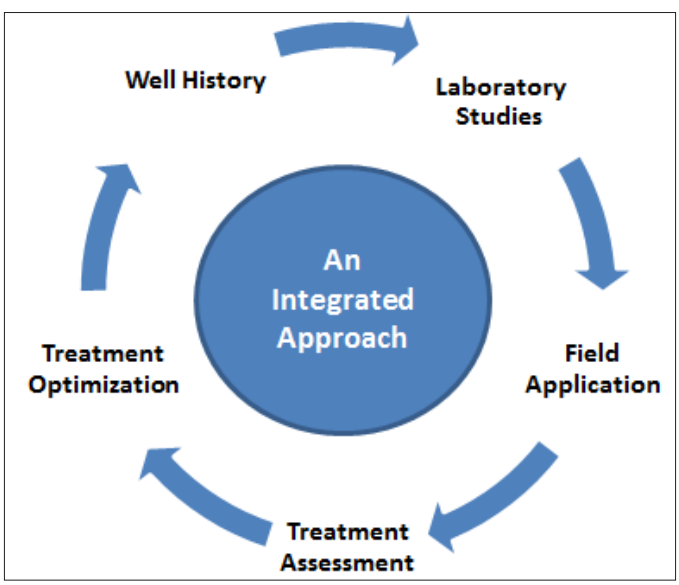

Fig. 1. Integrated method for well treatment.

Well-A was drilled as a horizontal open hole oil producer in a carbonate reservoir. The well was drilled in 2007 through a gas cap area with a directional hole. The well was completed with a 7" packer and 4½" tubing. The well was reported dead after the gas-oil separation plant that had received its production shut down in January 2011. In March 2011, 3.7" and 3½" gauge cutters were run and stopped at depths of 70 ft and 80 ft, respectively. In May 2011, a sample was collected from the first obstruction depth — 70 ft — and sent for lab analysis. In October 2011, another wireline gauge cutter, this time a 2½" gauge cutter, was run and continued until reaching 52° at 6,612 ft inside the tubing. In February 2012, a 3½" gauge cutter was run and stopped at a depth of 150 ft, where a downhole sample was collected for lab analysis.

Mechanism of Asphaltene Precipitation in Well-A. The cause of asphaltene precipitation in this field of interest, Field-A, is the stripping of asphaltene from the crude oil by gas[24]. Even though the oil reservoir is undersaturated, Field-A has two gas caps, which are attributed to gas injection during the 1960s and 1970s. A number of wells in Field-A show high gas-oil ratio (GOR) in the gas cap area. When asphaltene precipitation experiments were conducted[24] at reservoir conditions using a special pressure-volume-temperature apparatus, it was found that asphaltene precipitation and deposition increase with increasing GORs.

When gas is added to the crude — as may be happening during the production from the gas cap wells — the composition of the crude changes and may lead to precipitation as asphaltene is stripped from the crude oil. This is the same mechanism observed during de-asphalting of crude oil in a refinery where propane and butane are used for stripping the asphaltenes. When this happens in a well, the precipitated asphaltenes deposit near or in the wellbore, which may result in partial or total loss of well productivity.

Characterization and Identification of the Bailer Sample. Figure 2 shows two photos of the bailer sample obtained from Well-A. The bailer sample, which was collected at a depth of 150 ft in February 2012, contains solid material and oil. The sludgy material was separated from the sample and subjected to asphaltene and paraffin content measurement. Table 1 shows that the organic deposit contained mainly asphaltene, 81 wt%, and associated paraffin, 11 wt%. The analysis results suggest the need for a solvent capable of dissolving both asphaltene and paraffin. Figure 3 is a photo of the deposited organic material in the wellhead of Well-A.

SARA Analysis and Colloidal Instability Index of Reservoir Oil. To assess the stability of the oil in Well-A, a SARA analysis of the reservoir oil produced from an offset well was performed, and the colloidal instability index (CII) was measured as a sim-

Fig. 2. Bailer sample obtained from Well-A.

Compounds	Asphaltene	Paraffin	Aromatic and Resins
Concentration (wt%)	81	11	8

Table 1. Chemical composition of the organic deposit obtained from the bailer sample collected from Well-A

Fig. 3. Organic deposit in well manifold of Well-A.

ple tool to assess asphaltene stability, Table 2. From the SARA analysis, the CII or the ratio of the sum of asphaltenes and saturates to the sum of aromatics and resins was calculated as:

$$CII = \frac{\%\text{Saturates} + \%\text{Asphaltenes}}{\%\text{Resins} + \%\text{Aromatics}} \quad (5)$$

The CII is a screening criterion[25] that can be used to identify crude oil systems with deposit problems. The CII views a crude oil as a colloidal system made up of pseudo components, i.e., SARA content. Oils with a CII of below 0.7 are considered stable, while those with a CII of above 0.9 are considered very unstable. A CII of 0.7 to 0.9 is indicative of oil with moderate instability. The calculated CII for reservoir oil where Well-A is located was 1.1, indicating that it is very unstable and tends to precipitate asphaltenes.

Solvent System Selection

Different factors were considered in the selection of a solvent system, including solvency power, safety, environmental impact and cost.

Solubility of Organic Deposits Separated from the Bailer Sample. The solubility tests were performed on the organic deposits obtained from Well-A at different temperatures, including at the reservoir temperature of 220 °F, and also at different soaking times. The tests were conducted at static conditions, meaning without agitation. Tables 3 to 5 show the formulations for the different solvent systems used in the study.

Saturates (wt%)	Aromatics (wt%)	Resins (wt%)	Asphaltene (wt%)	CII
51.27	33.65	13.95	1.13	1.1

Table 2. SARA analysis of reservoir oil and the calculated CII

Additive	Asphaltene Specific Solvent	Diesel	Surfactant	Paraffin Specific Solvent
Concentration (vol%)	50	38	2	10

Table 3. Solvent System 1

Additive	Asphaltene Specific Solvent	Diesel	Surfactant	Paraffin Specific Solvent
Concentration (vol%)	30	58	2	10

Table 4. Solvent System 2

Additive	Solvent	Mutual Solvent
Concentration (vol%)	93	7

Table 5. Solvent System 3

Chemical	Temp. (°C)	Soaking Time (hr)	Solubility (%)	Observations/ Pressure (psi)
Solvent System 1	ambient	2	76	atm.
Solvent System 1	ambient	4	86	atm.
Solvent System 2	ambient	2	45	atm.
Solvent System 2	ambient	4	70	atm.
Solvent System 3	ambient	2	58	atm.
Solvent System 3	ambient	4	58	Hard to pass through the filter paper
Solvent System 1	50	2	78	atm.
Solvent System 1	50	4	83	atm.
Solvent System 2	50	2	45	atm.
Solvent System 2	50	4	70	atm.
Solvent System 1	50	6	86	atm.
Solvent System 1	70	4	91	atm.
Solvent System 1	104	1	77.1	at 500 psi
Solvent System 1	104	2	86.4	at 500 psi
Solvent System 1	104	4	93	at 500 psi
Solvent System 1	104	6	94	at 500 psi
Solvent System 3	104	6	68	at 500 psi
25 vol% xylene in diesel	104	6	33.98	at 500 psi
50 vol% xylene in diesel	104	6	77.40	at 500 psi

Table 6. Summary of solubility tests of Well-A organic deposit in several solvent systems

Table 6 provides a summary of the solubility tests performed on the Well-A organic deposit using different solvents. The results reveal that Solvent System 1 exhibited the best performance among the examined solvent mixtures. Solvent System 1 was able to dissolve 94 wt% of the organic deposit after aging for 6 hours at 220 °F and 500 psi, while Solvent System 3, at the same

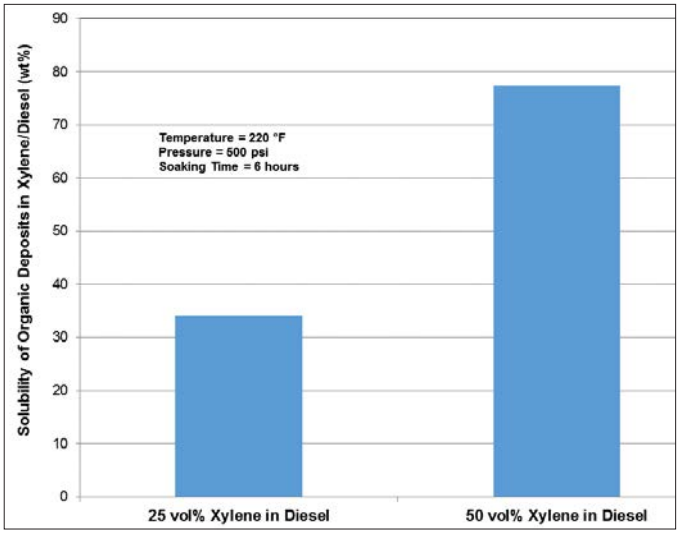

Fig. 4. Solubility of organic deposits in xylene-in-diesel systems.

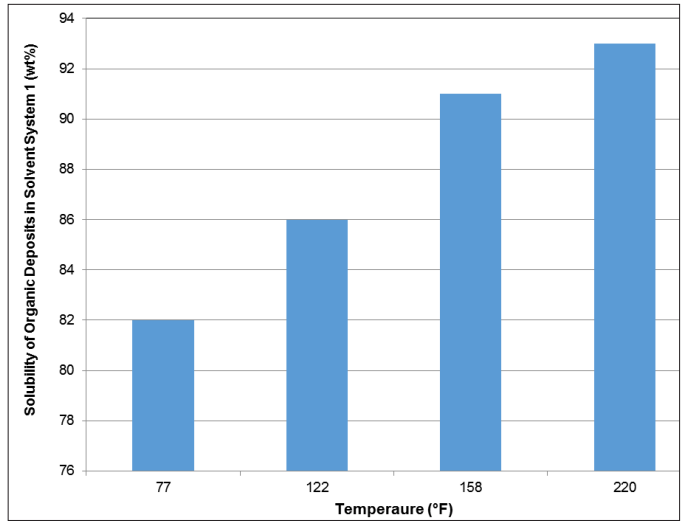

Fig. 5. Effect of temperature on organic deposit solubility in Solvent System 1 for 4 hours.

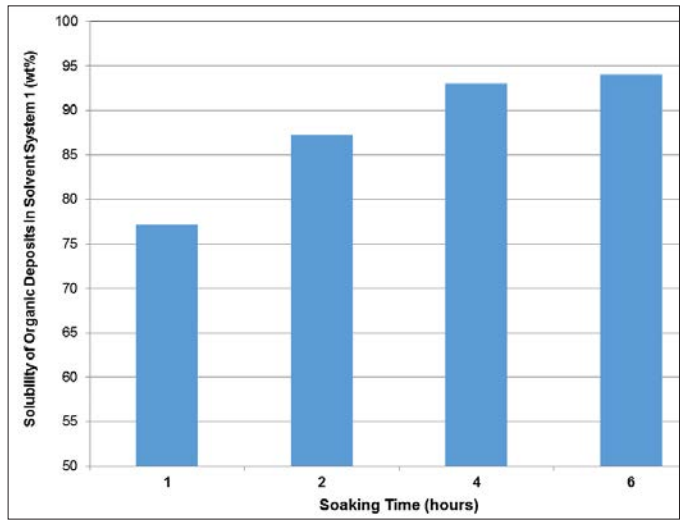

Fig. 6. Effect of time on organic deposits solubility in Solvent System 1.

conditions, dissolved only 70 wt%. A mixture of 50 vol% xylene and 50 vol% diesel was able to dissolve 77 wt%, Fig. 4.

The effect of temperature and soaking time on the performance of Solvent System 1 was investigated, as illustrated in Figs. 5 and 6, respectively. The results showed that the solubility of Well-A's organic deposit in Solvent System 1 increased from 82 wt% at a temperature of 77 °F to 94 wt% at the reservoir temperature of 220 °F. Both higher temperatures and longer soaking times tended to enhance the performance of Solvent System 1. Figure 6 shows that the organic deposit solubility reached a near plateau level after a soaking time of 4 hours. The results suggest that a soaking time of 4 hours is enough to dissolve the organic deposit, although a soaking time of 6 hours might be recommended to allow for a safety margin.

Cleanout Job Execution. The execution of the job conformed to the well's operational design. The pumping units and tanks were rigged up, the fluids were mixed, and the bullhead portion

Fluid Type	Direction	Distance (ft)	CT Speed (ft/min)	Pump Rate (bbl/min)
Solvent System	↓	210	30	1
Solvent System	↑	50	30	1
Diesel	↓	210	30	1
Diesel	↑	50	30	1
Diesel	↓	210	30	1
Diesel	↑	50	30	1
Solvent System	↓	210	30	1
Solvent System	↑	50	30	1
Diesel	↓	210	30	1
Diesel	↑	50	30	1
Solvent System	↓	TD	30	1
Solvent System	↑	Line shoe	30	1

Table 7. Cleanout schedule

of the job was completed at 3.5 barrels per minute (bpm) to 4 bpm, maintaining a wellhead pressure (WHP) between 900 psi and 1,100 psi — below the limitation of the 3,000 psi wellhead rating. After 100 bbl of solvent were spotted, the pressure was bled off, and the well was closed. In the meantime, the 1.75" CT unit was rigged up for the second phase of the operation. The CT was run in hole (RIH), and at 590 ft, the circulation pressure and WHP started to increase. The choke manifold was opened further in an attempt to bleed off the pressure, but no pressure decrease was seen. It was determined that the flow back lines and choke had asphaltene deposits as well. The CT was pulled out of hole (POOH) to the surface, and the well was closed. The choke manifold was then disconnected from the flow line, and it was discovered that the lines were completely plugged off, as can be seen in Fig. 3. The decision was then made to connect the return line from the flow back equipment to the first section of the production flow line and to flush it with the naphthalene oil-based dissolver, letting it react for a couple of hours. The second section of plugged flow line was flushed the same way.

After the soaking time, the lines were tested and found free of any obstruction, so the RIH operation with CT continued once more in the well. The CT was able to traverse the entire tubing section of the well without encountering any obstruction, showing evidence of the effectiveness of the solvent that had just been bullheaded. It was proposed to alternate batches of treated diesel and solvent system as per the sample schedule, Table 7. The CT performed the cleanout sweeping stages at the shallow portion of the open hole section before tagging the first hard fill at 9,030 ft. Below the aforementioned depth, the CT encountered several hard tags, where 2 bbl pills and later 5 bbl pills of the solvent system had to be spotted and given enough soaking time to react, before the CT was able to pass. Further tags were encountered at 9,080 ft, 9,362 ft, 9,374 ft and finally at 9,386 ft, where no more progress was observed. When the CT simulations for the 1.75" string were run, no lockup was predicted, so the obstruction at 9,386 ft had to be very dense. During the sweeping stages, the WHP was kept at around 1,000 psi, especially during the soaking stages, when trying to pass the obstructions.

After the CT reached 9,386 ft and was not able to pass through, it was decided to spot the dissolver from that depth at the same time that the CT was POOH up to the liner shoe, located at 7,416 ft. After the dissolver was spotted, the CT continued to be pulled to the surface and the well was closed for a final 12 hours. The well was opened after the soaking time, and flow back was immediately observed at the surface, returning treated diesel, the naphthalene oil-based dissolver and oil. After 24 hours of continuous flow back at a stable WHP, it was decided to release the CT unit, as there was no need for a nitrogen lift contingency.

Post-Treatment Result and Analysis. Following the cleanout treatment, the well was restored to its full production capacity prior to the organic damage. The post-treatment production rate indicated that the treatment had been effective in removing the organic deposition from Well-A, restoring its productivity. Asphaltene content measurements of the flow back samples collected during the treatment support this finding. Typical asphaltene content in Well-A's oil is around 1.0 wt%; however, asphaltene content in the flow back samples collected from Well-A reached up to 16 wt%, Fig. 7. This result demonstrates that the solvent was able to dissolve large amounts of precipitated asphaltene and that the overall cleanup treatment was effective in removing asphaltene deposition from Well-A.

Second Cycle

Two years after the first solvent treatment to remove asphaltene precipitation, Well-A saw a reduction in its production rate, which was attributed again to organic deposition. This section discusses the laboratory evaluation and optimization of different environmentally friendly solvents and inhibitors/dispersants. This section also describes the execution of a second treatment and presents an evaluation of its results.

Solubility of Organic Deposits Separated from the Bailer Sample. The solubility of organic deposits obtained from Well-A in different solvent systems at 220 °F and as a function of soaking times was studied. Several green solvent systems were investigated, and the results of the most effective one, Solvent System 4, are presented. This is a newly developed environmentally friendly solvent that is biodegradable and has a high flashpoint. Figure 8 shows the solubility of organic deposits in Solvent System 4 at reservoir temperature as a function of soaking time. Solvent System 4 was able to dissolve 90 wt% of the organic deposits after 1 hour, and the solubility increased to more than 98 wt% when the soaking time was increased to 3 hours. Increasing the soaking time to 5 hours did not add to the solubility, which indicates that the optimum soaking time is 3 hours.

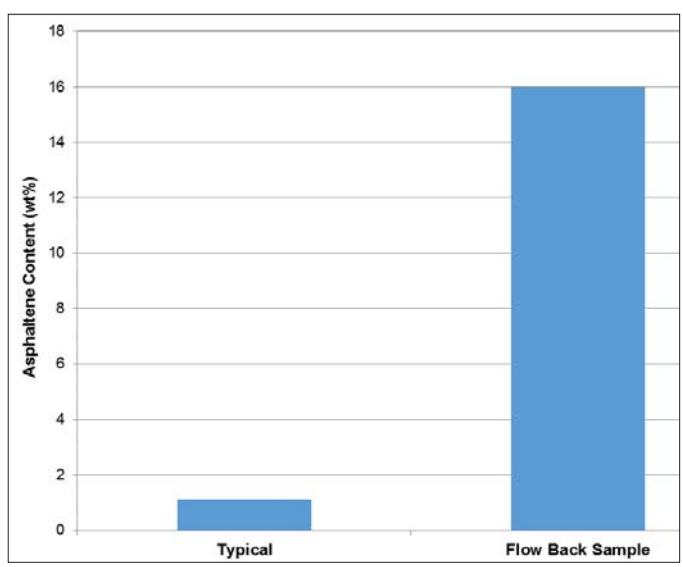

Fig. 7. Asphaltene concentration in flow back samples following the first cycle.

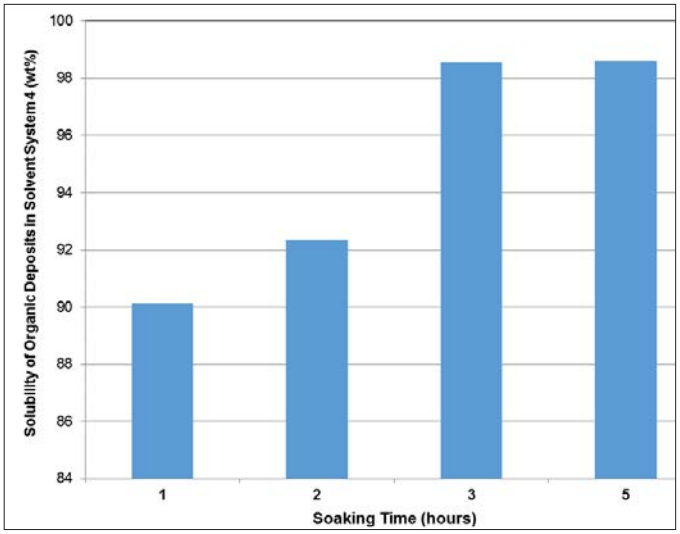

Fig. 8. Effect of time on organic deposits solubility in Solvent System 4.

Compatibility Study. The compatibility of this solvent system with freshwater, brine and diesel was investigated. Solvent System 4 was found to be incompatible with freshwater and with 7 wt% NaCl brine; in both cases, an emulsion was observed to form, Figs. 9 and 10. Solvent System 4 was compatible with diesel, Fig. 11; however, when nonionic surfactant was added to the 5 vol% solvent system, it was incompatible with the diesel. To assess the extent of the potential formation damage due to mixing of Solvent System 4 with the brine solution where it had a demonstrated incompatibility, a coreflood experiment at reservoir conditions was conducted. Solvent System 4 damaged the core saturated with 7 wt% NaCl, causing a reduction in core permeability of more than 75% — K_{brine} dropped from 302.6 mD to 65.5 mD, Fig. 12. These results show that Solvent System 4 was likely to damage the formation permeability in Well-A, and it was suggested not to use it to remove asphaltene in that well.

Selected Solvent System. An oil-based solvent system, Solvent System 5, examined in this study is relatively cheap compared with commercially available solvents. Solvent System 5 was able to dissolve more than 90 wt% of Well-A's organic deposits after aging at 220 °F for 24 hours. After Solvent System 5 was mixed with diesel at a 1:1 ratio, it was still able to dissolve more than 80 wt% of the organic deposits. Because it was cost-effective, this solvent system was selected for the second asphaltene removal treatment of Well-A. Solvent System 5 was expected to reduce the chemical cost compared with the previous treatment by 75%, while a reduction in total treatment cost of 60% was anticipated.

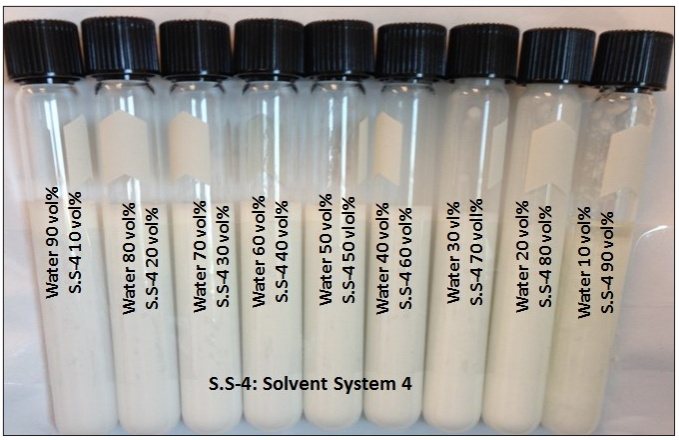

Fig. 9. Compatibility of freshwater with Solvent System 4 at ambient temperature.

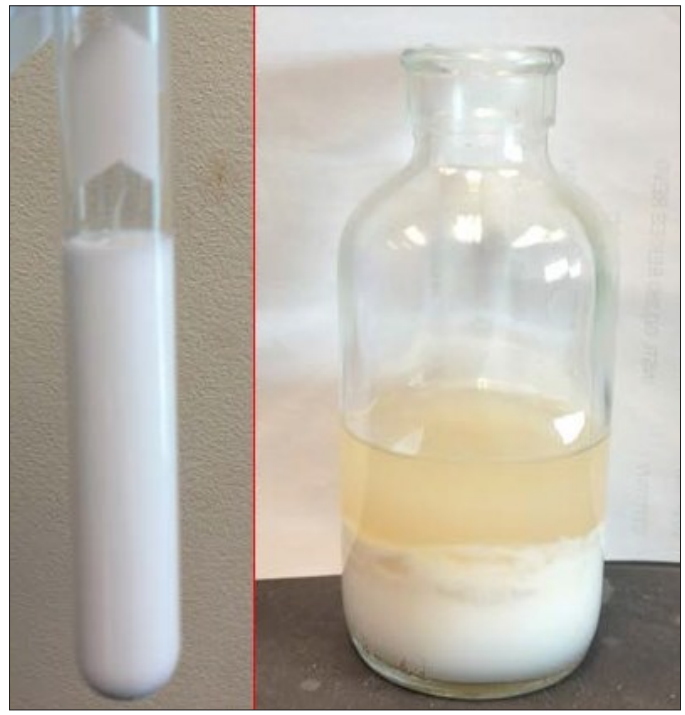

Fig. 10. Compatibility of Solvent System 4 with 7 wt% NaCl mixed at 1:1 ratio at ambient temperature.

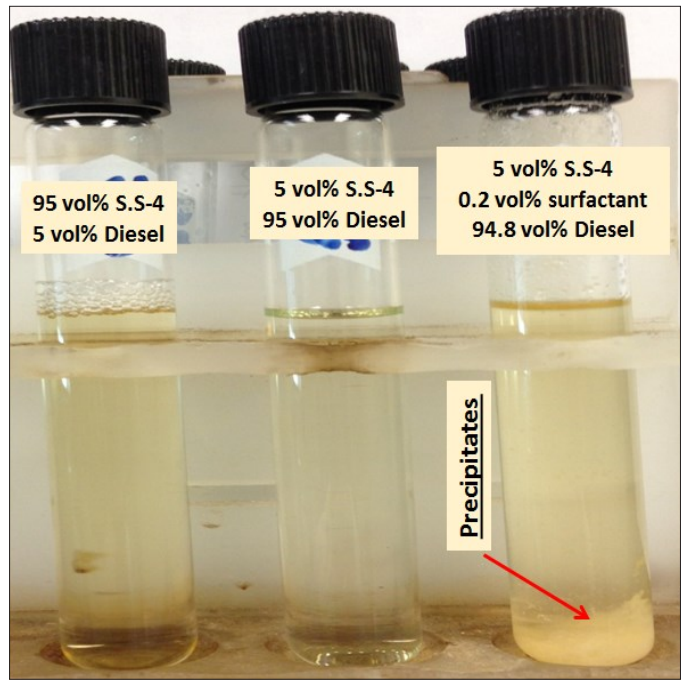

Fig. 11. Compatibility of Solvent System 4 with fresh diesel at ambient temperature.

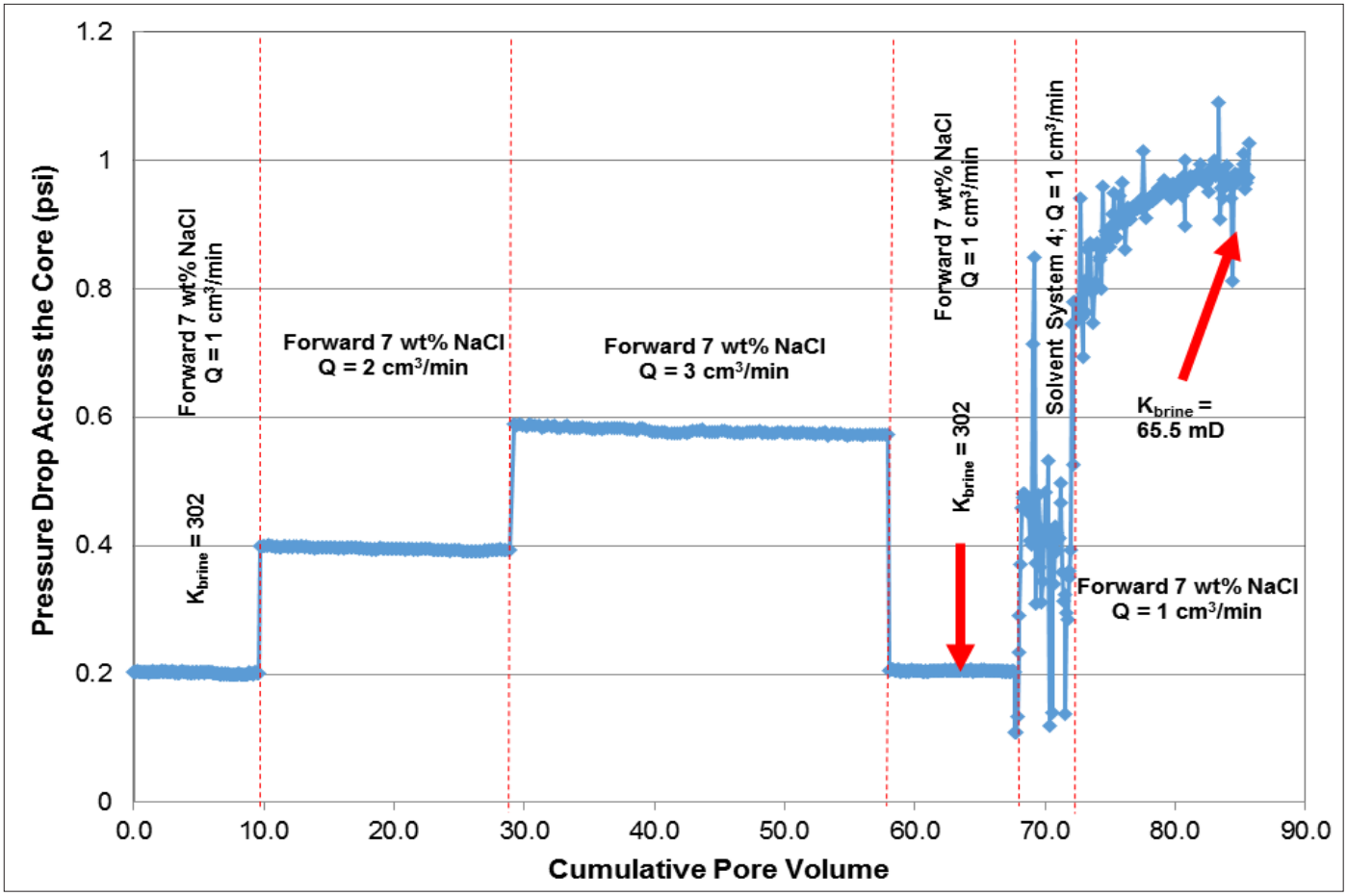

Fig. 12. Pressure drop across the core sample due to injection of 7 wt% NaCl and Solvent System 4.

Asphaltene Inhibition. The inhibition of asphaltene precipitation was another part of this study, and to investigate such inhibition, several dispersants were evaluated. Figure 13 (ADT with dispersant A) and Fig. 14 (ADT with dispersant B) show some of the obtained results. Compared to the long life of scale inhibitor squeeze treatments, the lifetime of asphaltene inhibitor treatments is much shorter, especially with high production rate wells such as Well-A. The anticipated lifetime of asphaltene inhibitor treatment is about two months, while the current practice finds that asphaltene deposition removal is needed every two years. Based on an economic feasibility study, asphaltene inhibition was excluded as a treatment option.

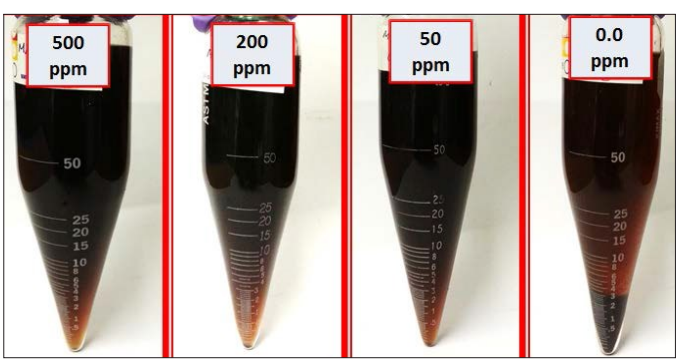

Fig. 13. ADT with dispersant-A.

Cleanout Job Execution

The cleanout job was executed using three stages as follows.

First Stage: Bullheading. A dissolver treatment — a solvent-diesel mixture at a 1:1 ratio — of 107 bbl was pumped by bullheading at a rate of 0.5 bpm to 1.2 bpm and a WHP of 1,300 psi. Once the bullheading was completed, the well was shut-in

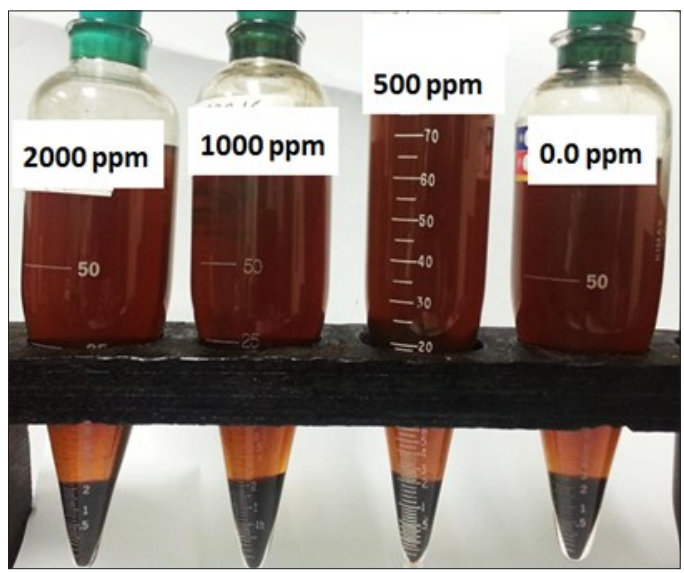

Fig. 14. ADT with dispersant-B.

at 1,100 psi WHP, and the treatment was left in the tubing for a 24-hour soaking time to dissolve the asphaltene in the tubing's inner diameter.

Second Stage: Asphaltene Cleanout. The crown valve was opened, and the CT started to RIH while performing a pull test and breaking circulation with 4 bbl of the solvent-diesel mixture at 1,000 ft intervals until reaching 6,000 ft. Once the CT reached 6,000 ft, the well was shut-in, and the asphaltene dissolver treatment was pumped at 1 bpm. The CT continued to RIH while checking weight every 1,000 ft until reaching 9,040 ft, where the tagged and slack weight was around 5,000 lb as shown on the surface indicator. Once the fill was found, CT started POOH to ensure it was free of the fill while continuing to pump the treatment. In total, four attempts to pass were made without success, as observed by slack off on the weight.

The CT started POOH from a depth of 9,000 ft while pumping the asphaltene dissolver treatment at a minimum rate until it reached 8,380 ft, where the pumped fluid was switched to pure diesel to displace the treatment. The pumping continued until the CT reached 6,000 ft, where the recorded shut-in well pressure was 950 psi. The CT was then POOH to the surface, and the treatment was allowed a 24-hour soaking time.

Third Stage: Wellbore Displacement. The crown valve was opened, and the CT started to RIH while performing pull tests and breaking circulation with 4 bbl of the solvent-diesel mixture at 1,000 ft intervals until reaching 8,728 ft, where the tagged and slack weight was around 4,000 lb as shown on the surface indicator. Once the fill was found, CT started POOH to ensure it was free of the fill until 8,685 ft, where it started pumping the solvent-diesel mixture and making other attempts to pass without success.

The CT was then pulled out to 8,650 ft, the well was opened by the flow line, and 70 bbl of the solvent-diesel mixture were pumped. An increase in WHP from 650 psi to 1,050 psi was observed. Once the treatment was pumped, the CT started POOH while pumping pure diesel at the minimum rate until reaching 6,260 ft. At this point, the pumping stopped, and the CT continued to POOH until reaching 3,000 ft, where the WHP was monitored for 3 hours. Once it was determined that the WHP was stable, the CT continued to POOH to the surface.

Post-Treatment Result and Analysis

Following the cleanout treatment, the WHP increased by 40%. The post-treatment WHP indicated that the treatment was effective in removing organic deposition from Well-A and restoring its initial productivity. Asphaltene content measurements of flow back samples collected during the treatment supported this finding. Typical asphaltene content in Well-A's oil is around 1 wt%; however, the asphaltene content in most of the flow back samples collected from Well-A was more than 3 wt%, Fig. 15.

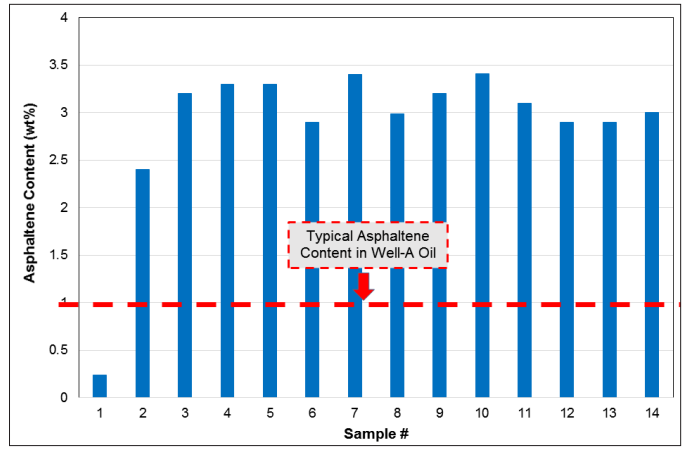

Fig. 15. Asphaltene concentration in flow back samples following the second cycle.

These results revealed that the solvent was able to dissolve large amounts of precipitated asphaltene and that the overall cleanup treatment was very effective in removing asphaltene deposition from Well-A. As expected, the optimized treatment reduced the cost of chemicals by 75% and the total treatment cost by 60%.

CONCLUSIONS

1. An integrated approach was applied successfully to restore/improve the productivity of a well damaged by organic deposition.
2. Well-A was damaged with the precipitation of asphaltene associated with paraffin.
3. The mechanism of asphaltene precipitation in Well-A is a high GOR. As determined from the CII, the oil was found to be highly unstable and likely to precipitate asphaltene.
4. First, the productivity of Well-A was restored using an optimized, efficient solvent system.
5. After two years, a more cost-effective solvent treatment was successfully applied to improve the productivity of Well-A.
6. Inhibition treatments were not feasible from an economic point of view. More work is required to improve asphaltene inhibitor adsorption on the rock surface and to elongate the lifetime of inhibition treatment.

RECOMMENDATIONS

1. Prior to the shut-in of any well within a gas cap area, a solvent or an inhibitor/dispersant should be injected in the wellbore to prevent asphaltene precipitation.
2. Oil wells in this area should be produced with a gas cap at a minimum possible GOR. This will reduce the amount of asphaltene precipitation and subsequent deposition.
3. Some type of inhibition strategy, based on more research and data collection, should be considered for long-term protection against asphaltene precipitation in this area.

ACKNOWLEDGMENTS

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First Ever Well Intervention Using a Multispinner Production Logging Tool Conveyed via Coiled Tubing in an Innovative Pseudo-Multilateral Completion in a Saudi Arabia Oil Field — A Story of Success

Fowzi O. Al-Shammari, Adel S. Al-Thiyabi, Rifat Said, Majid M. Rafie, Mohammad Arifin, Kaisar Al Hamwi and Danish Ahmed

ABSTRACT

Throughout the history of the oil and gas industry, numerous developments have been made in drilling. In Saudi Arabia, wells that historically have been drilled and completed as vertical and deviated wells have been completely shifted to horizontal wells and even past that to extended reach and multilateral wells. Horizontal wells have enhanced the draining of relatively thin formation layers by maximizing reservoir contact; they have also decreased water and gas coning, increased exposure to natural fracture systems in the formation and achieved better sweep efficiencies. On the other side, drilling a horizontal well and further drilling a lateral add to the complexity of the well's operation with respect to lateral accessibility, especially during workover and well intervention services.

To further address the challenges associated with the drilling and completion of multilateral wells, and later well intervention, an innovative completion was installed for the first time ever in an oil well in Saudi Arabia. The innovative completion technique introduced the idea of pseudo-multilaterals, where the laterals are not actually drilled but the completion instead consists of "needles" that extend into the formation, enabling the well to have more reservoir contact.

The innovative pseudo-multilateral completion was installed for the first time during a workover operation in an oil well in Saudi Arabia. The well was initially completed as an open hole in a tight formation with an electrical submersible pump (ESP). Prior to installation of the innovative pseudo-multilateral completion, the well was facing issues in achieving sustained production, and though the well was stimulated using coiled tubing (CT), that intervention did not meet the objectives. After the installation of the innovative pseudo-multilateral completion, however, followed by another stimulation intervention, the well was able to produce at a stabilized production rate.

To evaluate the effectiveness of this pseudo-multilateral completion technology, multispinner production logging via CT was conducted to determine which of the pseudo-multilaterals were contributing to the inflow. Since this was the first production log recorded in this new type of completion, the logging bottom-hole assembly and procedures were modified to overcome challenges such as establishing the internal geometry and profile. The production logging was executed successfully, and the multispinner production logging analysis shows a homogeneous production profile. The logging results provided the input used later in optimizing the pseudo-multilateral completion and gave researchers the confidence to pursue this technology in other applications.

This article presents the process followed in designing, executing and evaluating the first production logging in the pseudo-multilateral completion. It examines the benefits and challenges of running production logging in such a completion. In addition, it displays the advantages and disadvantages of installing a pseudo-multilateral completion using evidence from well testing through production logging.

INTRODUCTION AND BACKGROUND

Field Introduction

Field A is the second largest onshore field in the Kingdom of Saudi Arabia. The field was discovered in 1957 through surface and gravity mapping. Field A has been produced intermittently throughout its history under primary depletion.

In Field A, hydrocarbon accumulation in Zone A lies within an elongated, north-south trending, asymmetrical anticline with the lower limits defined by a tight aquifer. The Zone A reservoir is a few hundred feet thick and consists primarily of clastic limestones, with smaller amounts of fine-grained limestone and dolomite. Zone B, located a few hundred feet below Zone A, is of lower rock quality and has a higher degree of fracturing. The oil quality in both reservoirs is Arabian Light crude oil. The two reservoirs, Zone A and Zone B, are separated by a thick (~300 ft) layer of nonporous limestone.

EVALUATING THE COMPLETION STRATEGIES DURING THE COMPLEX DEVELOPMENT OF FIELD A

In anticipation of water encroachment many years in the future, the wells were designed with large wellbores of 8½" and completed with Y-tools — for wellbore accessibility — so that they would be able to accommodate the next-generation smart completions, either completions with inflow control valves (ICVs) or passive inflow control device completions, together with highly efficient, coiled tubing (CT) deployed electrical submersible pump (ESPs)[1, 2]. Smart completions became an important and complementary technology for the development of the two reservoirs of interest. The multiple pay environment calls for commingling production from these reservoirs — Zone A and Zone B — to reduce development costs and optimize field development. The need to control fluid production from each reservoir is critical, especially in the areas of proven inter-reservoir communication. Fractures have been identified in both Zones A and B and are suspected to be conduits for the communication between the reservoirs. The application of smart wells equipped with ICVs, Fig. 1, is thought to be the only way to control and optimize fluid production from separate laterals in the separate reservoirs without a major workover operation. It is thought that such an application will control the waterflood sweep efficiency in the individual reservoirs and extend the life of the wells[3].

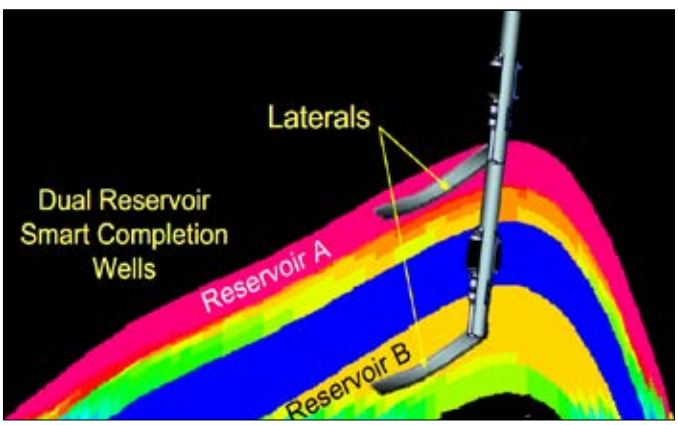

Fig. 1. Schematic of dual reservoir commingled smart completion.

These technologies and this completion style are used in cases where the commingled production from two reservoirs is needed. While the completion methods for commingled production from two reservoirs are being optimized, wells are being completed typically only in one reservoir at a time, so those completion methods must also be consistently evaluated. It was in these circumstances that a horizontal oil producer well was drilled in Saudi Arabia in Zone B of Field A and a pseudo-multilateral completion was installed. The purpose of the pseudo-multilateral technology is to increase well productivity (or injectivity in the case of injection wells) by better connecting the reservoir to the wellbore. The technology is applicable in low permeability formations to create negative skin similar to that achieved by the hydraulic fracturing process. It is useful for reservoirs that are[4]:

- Compartmentalized, layered or naturally fractured.
- Without barriers to contain hydraulic fractures.
- Depleted in areas where the placement of a hydraulic fracture is challenging.
- With insufficient depth accuracy for sweet spot well placement.

The pseudo-multilateral technology has a liner sub that houses four small diameter, high-strength tubes called needles, each with a jet nozzle on the end, Fig. 2 (left). The sub is made up to a full-length casing joint, and needle assemblies up to 40 ft long are installed in the workshop before the sub is sent to the field. Multiple subs are then run as integral parts

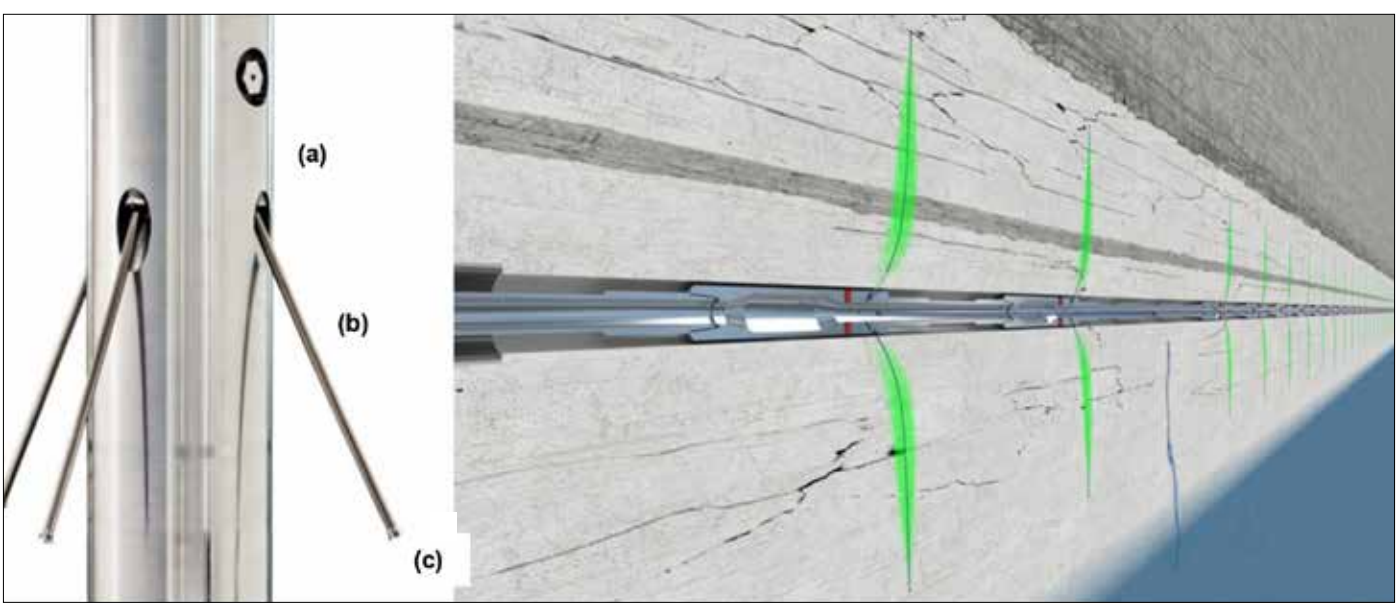

Fig. 2. Left – The sub (a), with needles (b), and jet nozzles (c), Right – pseudo-multilateral completion system.

of the liner in the open hole, positioned across the formation where stimulation is desired. The needles are kept inside the sub/liner joints while the equipment is run in hole (RIH). The liner is hung off with a standard liner hanger. In a carbonate formation, a basic hydrochloric (HCl) acid fluid system is then pumped.

The fluid jets out of the nozzles at the ends of the needles, and the formation in front of the tubes is blasted away by a combination of erosion and acid chemical dissolution. Differential pressure across the liner then drives the needles into the formation, and they penetrate the rock until fully extended. Typical jetting pressure is 3,000 psi. All pseudo-multilaterals are created simultaneously in one short pumping job, resulting in a fishbone-style well completion with pseudo-multilaterals extending from the mainbore, Fig. 2 (right).

The rate of penetration for the needles depends on the formation composition, porosity, downhole temperatures, nozzle configuration, jetting fluid and jetting pressures. The needles exit the sub at an approximate 40° angle. The bending through the exit port results in pseudo-multilaterals with a final angle of approximately 90° relative to the wellbore. The needles may be equipped with a positive identification mechanism that shuts off the flow when the needle is fully extended. A pressure indication on the surface signals that jetting is complete and a needle has fully extended into the formation. A fit-for-purpose float shoe enables circulation while running in the hole, but closes upon contact with the pumped acid, providing a closed pressure system for jetting.

Depending on the length of the horizontal wellbore, downhole temperatures and the number of pseudo-multilateral hubs, a number of open hole anchors are positioned in the liner to eliminate axial liner movement during jetting. An anchor with 33,000 lbf anchoring capability has been developed and qualified, and it is effective even in washed out zones. The acid jetting and the subsequent dissolution of the carbonate formation create lateral tunnels of ½" to ¾" diameter or larger. The oil will predominantly flow in the pseudo-lateral/needle annuli and into the mainbore, where it will flow through production valves in the subs, into the production liner and up the well. Each sub has two production valves phased 180° apart. These valves do not allow outward flow during the jetting process, but enable inflow during production[4].

MULTISPINNER PRODUCTION LOGGING

Production logging has two important applications: (1) measuring well performance with respect to reservoir dynamics, and (2) analyzing mechanical problems in the borehole. Different scenarios where production logging can be conducted include: (1) in new wells to evaluate initial production and verify the integrity of the completion, with a special use in horizontal, high rate wells to verify friction-induced production loss in long drain holes; (2) in any well that shows a sudden decrease in production or increase in the gas-oil ratio or water cut; (3) periodically in wells to detect problems such as water or gas coning, or fingering, before extensive production loss occurs; and (4) in injection wells so they may be initially analyzed and then monitored with production logging tools (PLTs)[5].

In the 1940s, a spinner for flow rate and pressure measurements was added to temperature surveys to obtain more detailed information about the wellbore, i.e., with the added data, the type of fluid can be identified using a pressure derivative. In the late 1960s, density and capacitance meters were introduced to solve complex multiphase flow behavior. The evolution of the PLT continued in accordance with the introduction of deviated and horizontal wells. Such wells can have complex flow regimes that are difficult to interpret with conventional production logging sensors. Traditional production logging uses flow meters (spinners) for velocity, gradiomanometers for density, capacitance meters for holdup, manometers for pressure and thermometers for temperature[6].

Depending on the well type, different styles of PLTs are utilized. In vertical wells, standard PLTs provide different measurements that can include telemetry, gamma ray, casing collar locator (CCL) data, pressure, temperature, gas holdup, gas/liquid bubble count, one-arm caliper data, relative bearing, velocity, X-Y caliper data, water holdup, water/hydrocarbon bubble count, and relative bearing. In horizontal wells — in addition to the basic measures of gamma ray, CCL data, caliper data, deviation, pressure, temperature, relative bearing, and tension — PLTs provide measurements of fluid velocity, water and gas holdup. If a single spinner is run in horizontal wells, and a centralized spinner does not cover the circumference of the hole, it can lead to the wrong interpretation in multiphase flow. Therefore, a tool as presented in Fig. 3, which has been used in recent years, is known as a multispinner PLT.

The objective of either single or multiple spinners is to evaluate water and hydrocarbon flow rates using electrical probe (EP) data and gradiomanometer measurements[7]. The EPs can be combined with a PLT to provide an indication of flow segregation. This can improve interpretation, reduce uncertainty, and supplement gradiomanometer data, which otherwise may have insufficient resolution for a reliable interpretation to be made[8]. Figure 4 is an illustration of the multispinner PLT. Descriptions of certain PLT components are provided below.

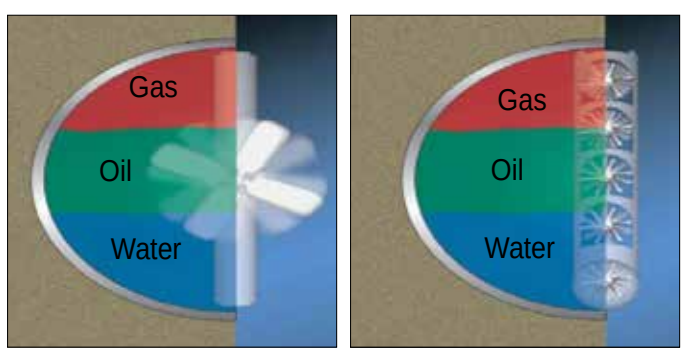

Fig. 3. Single spinner vs. integrated horizontal multiphase PLT in horizontal well logging.

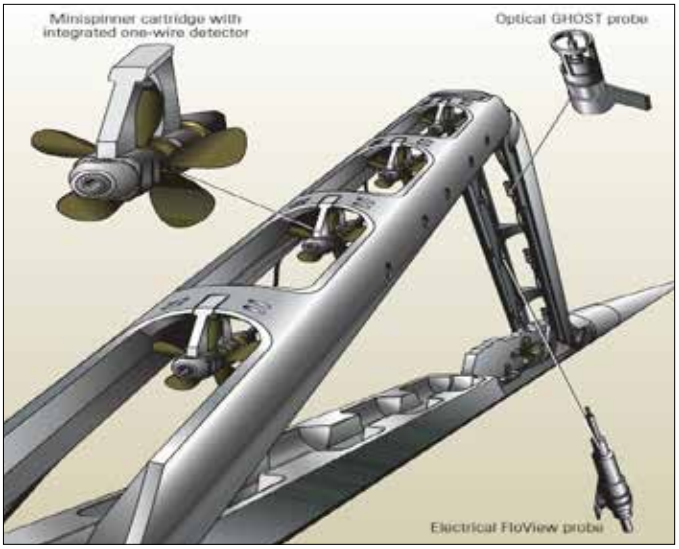

Fig. 4. Multispinner PLT.

Spinner (flow meter): Flow meters measure different flow rates. These flow rates are determined based on the position of the flow meters in a borehole and the flow type. The rate of spinner rotation is proportional to the movement of fluid relative to the spinner. The spinner rotation is affected by fluid and tool velocity, fluid density and the viscosity of the fluid[9].

Gradiomanometer: Borehole fluid density is one of the basic measurements of production logging. The tool computes density by measuring the pressure difference between two points with a known distance between them. The difference in pressure is used to derive density[9].

EP: The measurements of holdup are based on the electrical impedance difference between liquid or gaseous hydrocarbons and water. The tool comprises four EPs, located in centralizer arms. These four probes provide four independent digital holdup measurements around the wellbore. They can also identify individual bubbles of a dispersed phase and provide an output bubble count from each EP to identify the bottommost fluid entries, Fig. 5. The EP in conductive water provides a direct measurement of discrete water holdup at that point across the wellbore and depth[9].

Gas Holdup Optical Sensor Tool: This sensor, which is based on fiber optical technology, is a versatile tool with the capabilities of locating the first entry of liquid in a gas well or the first entry of gas in a liquid well. The tool uses the optical properties — refractive index — of fluids to differentiate gas from liquid in downhole conditions[6], Fig. 6.

CT INTERVENTION

To conduct a production logging run to evaluate a new completion approach, a proper selection of deployment methods needs to be considered.

PLTs are normally run on conventional wireline or CT pipe. To overcome any reach issues when using wireline, a tractor can be used to achieve target depth; however, CT is preferred for the following reasons:

- The CT pipe allows continuous pumping of nitrogen gas if needed to produce the well if it cannot flow naturally.
- The CT pipe is more rugged and has a higher force compared to wireline and tractors when it comes to pulling capacity.

After CT was selected as the deployment method for the PLTs in this completion evaluation, a full risk assessment took place to ensure the CT would complete the operation successfully; the risk assessment included stuck pipe prevention measures. One of the common risks involved in both CT and wireline operations is a stuck situation, where the deployment tool cannot be pulled out of the hole; this situation can be either

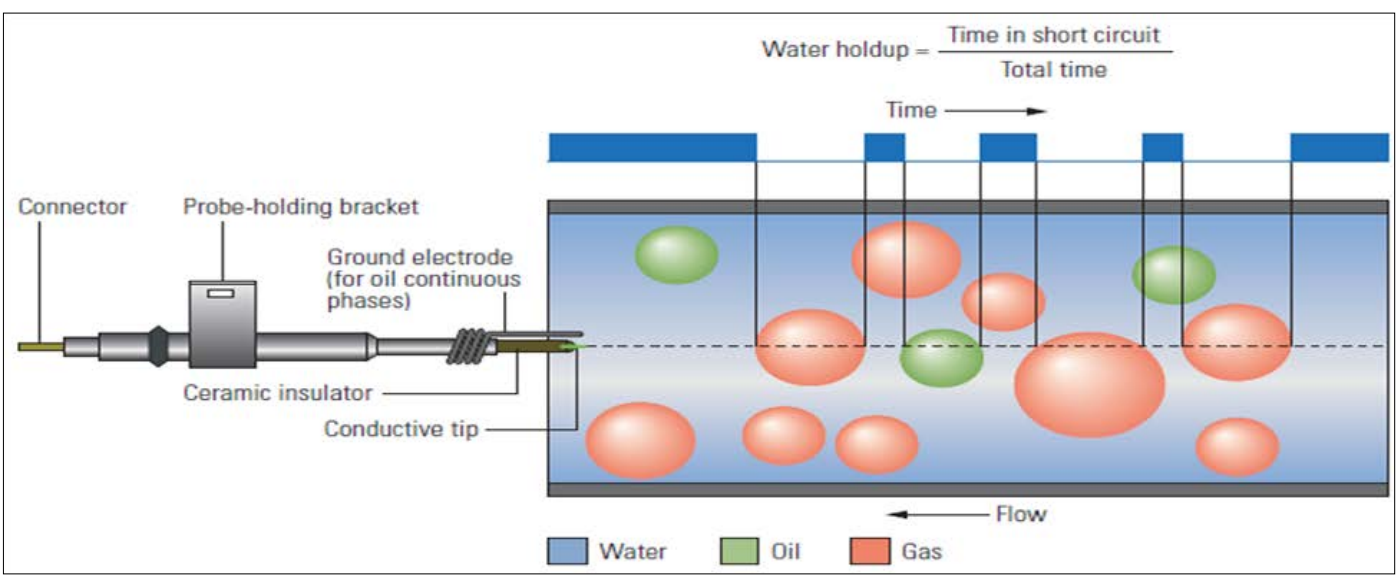

Fig. 5. Calculation of water holdup.

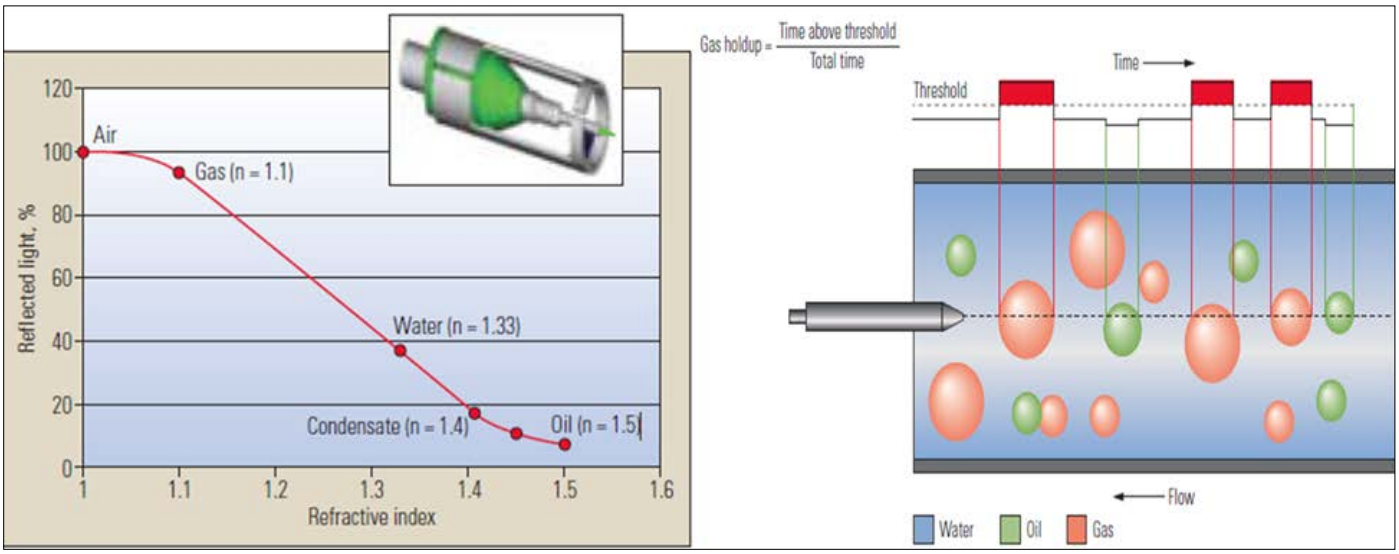

Fig. 6. Reflected light vs. the refractive index of various possible borehole fluids and the calculation of gas holdup.

mechanical or differential. Because this was the first ever deployment of PLTs in such a completion, a robust deployment tool such as CT was needed to overcome any sticking issues.

The pseudo-multilateral opening to the wellbore can create a restriction if it is not cut properly after installing the completion; therefore, a dummy tool was deployed in the well along with the tension and compression sub to evaluate the wellbore's condition prior to the main production logging run. The CT pipe along with the dummy tool successfully accessed the well to total depth (TD) and was safely retrieved to the surface without any major concerns. Subsequently, further operations conducting production logging with the actual tools were completed successfully.

CASE STUDY

The following case study provides operational details of the first-time use of CT for a multispinner production logging operation conducted to evaluate a pseudo-multilateral completion.

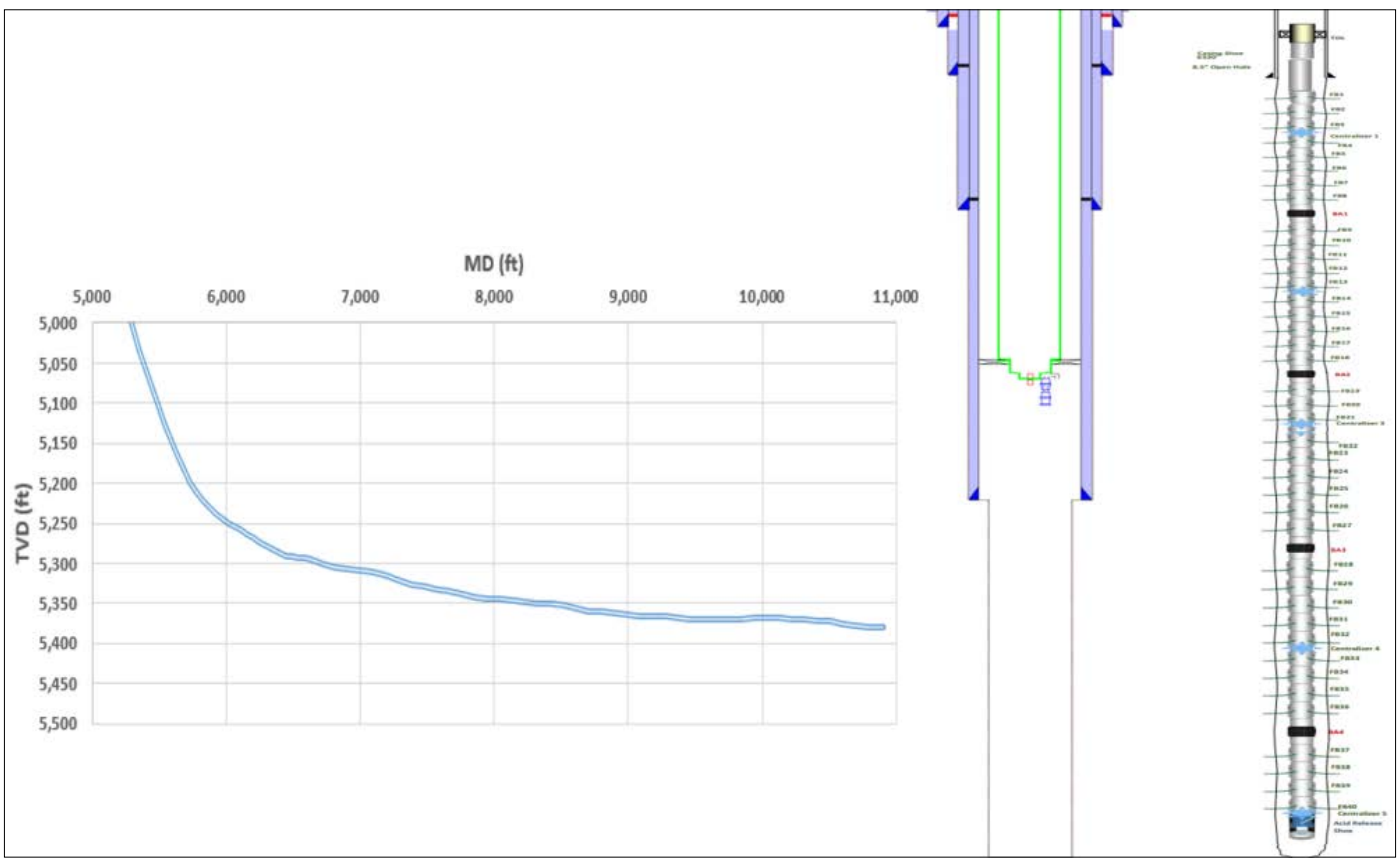

Fig. 7. Deviation survey (left), wellbore schematic (middle), and pseudo-multilateral completion (right) of Saudi Arabia's first well completed with a pseudo-multilateral completion.

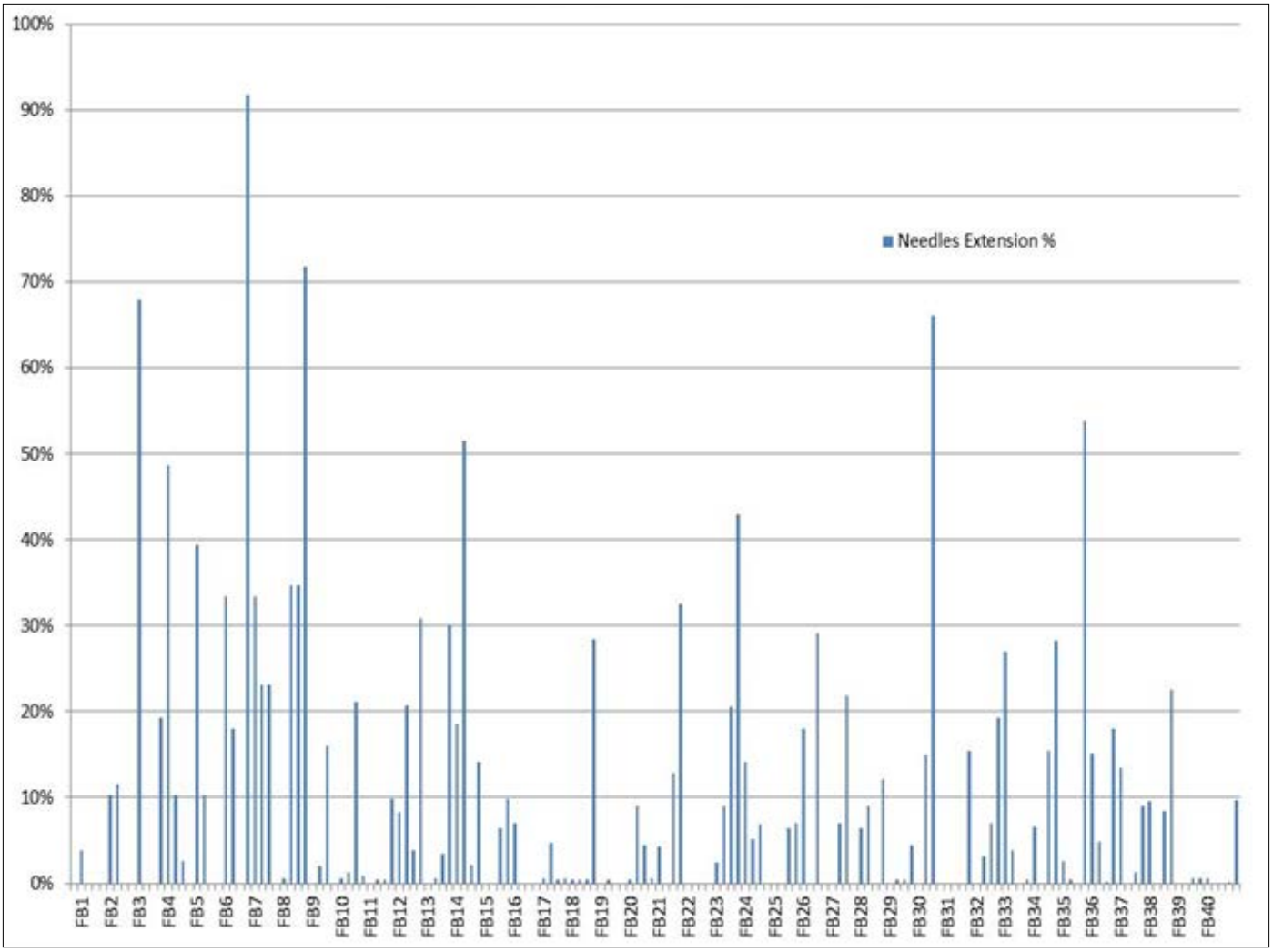

Fig. 8. Flow profile summary of multispinner production logging showing results after installing the pseudo-multilateral completion.

Well Details

A multispinner production logging operation was conducted for a pseudo-multilateral completion for the first time in a horizontal oil producer in Zone B of Field A. The well had the following characteristics, Fig. 7:

1. Well Deviation: Horizontal, single lateral
2. TD: 10,908 ft measured depth, 5,380 ft true vertical depth
3. Maximum Deviation: 90.56° at 9,628 ft
4. Tubing: 4½", 3½", 2⅞" tubing shoe at 4,765 ft
5. Completion Type: Pseudo-multilateral completion with ESP

Well History

The candidate well was drilled in July 2008 across Zone B to a TD of 10,908 ft, with a reservoir contact of 4,578 ft. No losses were encountered during drilling. The well was completed as a single lateral, cased hole — 5½" liner screens — Zone B oil producer, equipped with 4½" tubing, a Centrilift 47 stage P75 pump, a 161 HP 2304/44A motor, a Y-block assembly to facilitate reservoir access, and a Hydrow II dual bore packer; however, the well could not sustain flow.

In July 2015, the well was recompleted with a 5½" pseudo-multilateral completion and acid stimulation. This was the first pseudo-multilateral completion in Saudi Arabia. A 20% HCl acid solution was pumped and followed by a clean out and a needles cutting run. The initial finding indicated that most of the needles had not extended as per the plan. A new ESP was installed, and prior to rig release, was successfully function tested.

Installation of Pseudo-Multilateral Completion

Three success criteria were identified for the first ever installation of a pseudo-multilateral completion in Saudi Arabia:

- Criteria 1: No major issue on safety and service quality.
- Criteria 2: Pseudo-multilateral completion installed as per the job procedure and technical specification.
- Criteria 3: Stimulation pumped as per the job design with a minimum 60% of needles fully extended, based on pressure response and/or the needles' cutting recovery operation.

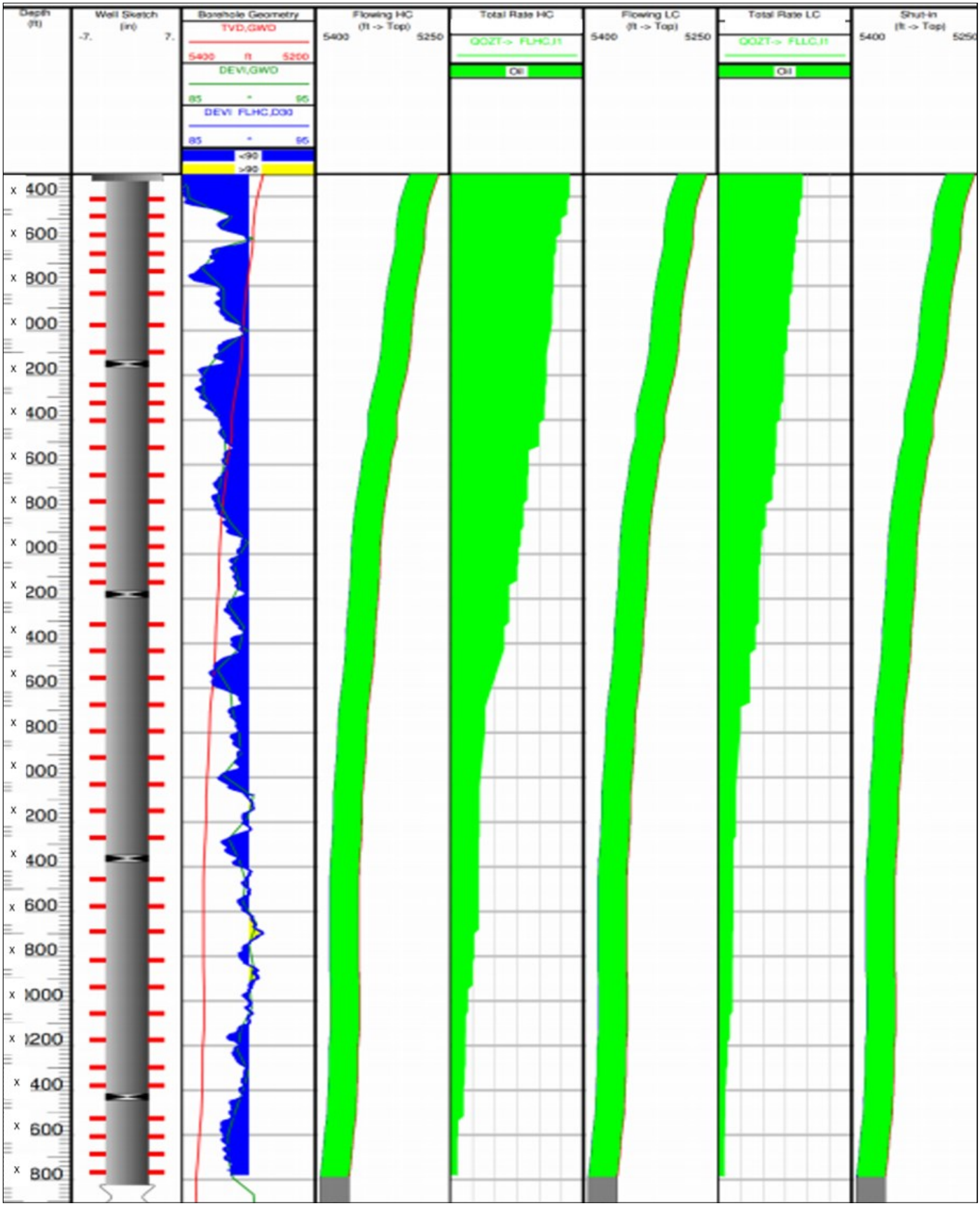

Fig. 9. Flow profile summary of multispinner production logging showing well production.

After the installation of the pseudo-multilateral completion, Fig. 8, the criteria results were as follows:

- Criteria 1:
  - Success — There were no safety and service quality issues observed.

- Criteria 2:
  - Success — The completion was installed as expected without any problems.
- Criteria 3:
  - The activation of the pseudo-multilateral completion hubs was observed based on pressure spikes in the downhole pressure gauge.
  - The majority of the needles were not extended. There was no pressure indication of full needle(s) extension. This was confirmed by fish basket runs.
  - Only one needle extended up to 95% of its designed length, and 66 needles did not extend at all. The cumulative length of the extended needles was 601 ft out of the projected 6,240 ft (10%).

Multispinnner Production Logging

A 2" CT pipe was used for performing the multispinner production logging in the candidate well. Figure 9 is a profile summary of the results of the multispinner production logging conducted in the following logging sequence:

1. Logging conditions:
   - Flow survey at 55% choke (high choke), 475 psi flowing wellhead pressure (FWHP)
   - Flow survey at 45% choke (low choke), 577 psi FWHP
   - Shut-in survey at 202 psi shut-in wellhead pressure
2. Logging sequence:
   - Flowing survey (55% followed by 45% choke), and finally shut-in survey
3. Logging passes:
   - 55% choke: one down pass and one up pass, plus 11 stations
   - 45% choke: one down pass and one up pass, plus 11 stations
   - Shut-in: one down pass and one up pass, plus six stations

CT Intervention Challenges

The biggest challenge for this operation was to accurately simulate the CT reach across the horizontal section, which extends for almost 4,500 ft. Therefore, a database for the friction coefficient (FC) used to simulate the CT reach was developed; the database considers well geographical location and completion type, whether cased hole or open hole. This database was built by comparing predicted weights vs. actual ones during the operation, then modifying the FCs to get weights to match. The simulation showed that the CT pipe would encounter lockup 2,000 ft from TD and that the coverage of the target interval would be only 56%. Subsequently, with the use of friction reducers and extended reach techniques, such as displacing the CT to nitrogen, it was believed the CT reach could be extended to 100%. It is important to note that during the actual job no friction reducer or nitrogen was pumped.

During the execution phase, the predicted weight matched with the measured weight for the tubing, but there was an offset of a few thousand pounds for the weight predicted for run-

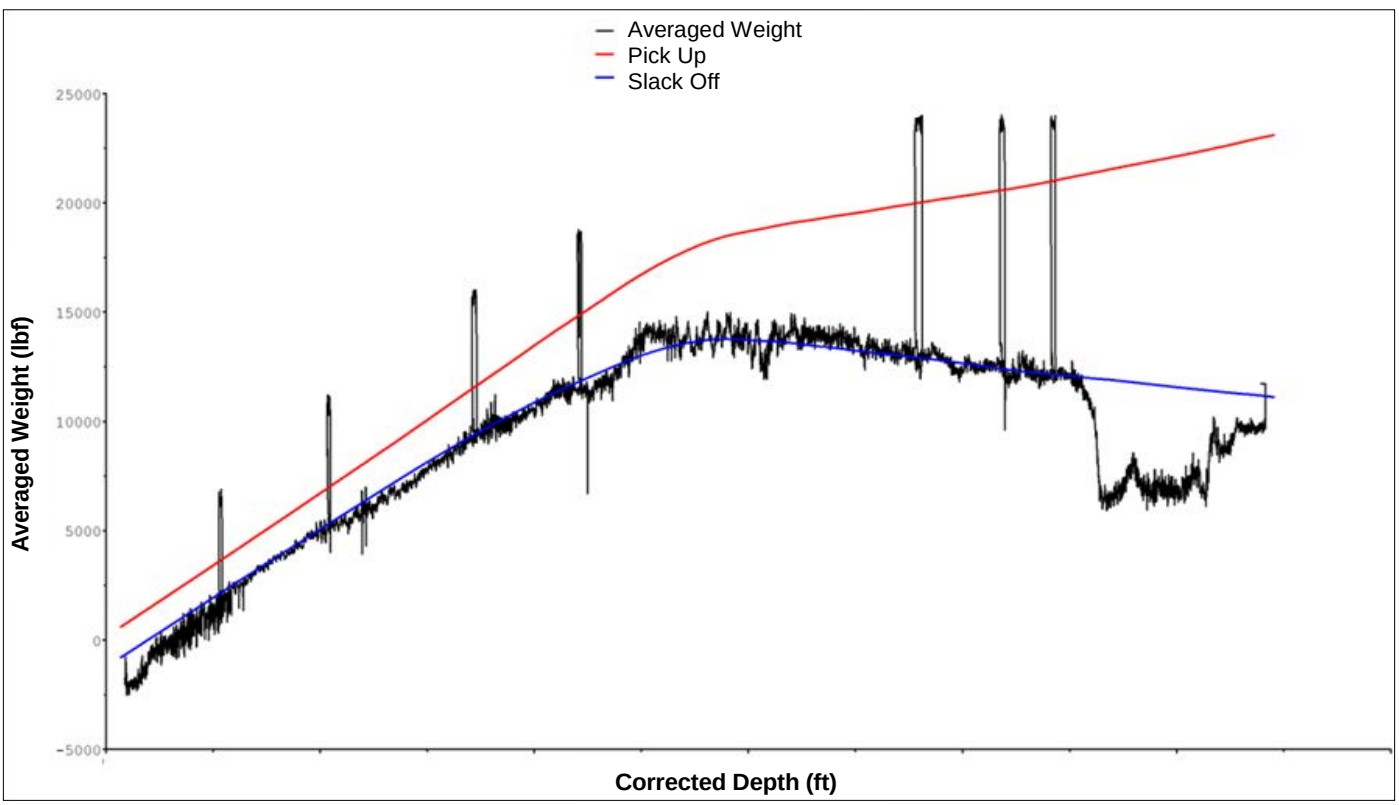

Fig. 10. CT pipe predicted weight vs. actual weight.

ning the CT pipe in a fishbone completion. Therefore, lower values of the FC were used to match the weights. The CT pipe continued to RIH all the way to TD, and 100% coverage of the target interval was achieved, confirming proper selection of friction coefficients. It should be mentioned that the CT pipe encountered a noticeable drag 1,000 ft above TD. Because this was not related to the friction coefficients used, it could be due to roughness caused by some protruding elements in the pseudo-multilateral completion that may have not been cleaned properly.

Figure 10 shows the CT pipe weight trends during the initial run in the well.

The blue line is the slack off weight during RIH, and the black line is the actual job data. The slope of the line accords directly with the FC selection, while the separation between the blue line and the red line (pick up weight) is in direct relation to the wellhead pressure, the stripper friction load, and the density of fluids in both the CT pipe and the well. The actual weight (black line) follows the same slope of the predicted one (blue line), indicating the friction coefficient selection is correct for this type of completion. The extra slack off noticed (at the right end of the plot) did not correspond to any effect on the tension and compression sub of the PLTs, meaning that the CT was not tagging an obstruction, but was more likely dragging against a rough surface. It is notable that if a wireline and/or tractors had been used, having this type of drag could have led to a situation where the PLTs could not reach to TD. Therefore, the use of CT was beneficial and enabled the achievement of the full profile of the producing interval.

CONCLUSIONS

The following are the results of the multispinner production logging in Saudi Arabia's first pseudo-multilateral completion:

1. At both choke settings, the downhole flow profile is considered uniform, since all logged fishbone completions were contributing to total flow and there was no zone dominating the total flow.
2. At both choke settings, a small amount of water was reported at the surface during multispinner production logging.
3. No cross flow was observed during shut-in and the flowing surveys.

Therefore, the pseudo-multilateral completion was installed successfully, and the multispinner production logging through CT was conducted successfully.

ACKNOWLEDGMENTS

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BIOGRAPHIES

Fowzi O. Al-Shammari is the Superintendent of the Khurais and Central Arabia Well Services Division of Saudi Aramco's Southern Area Well Completion Operations Department. He has been with Saudi Aramco for 17 years. During his earlier career, Fowzi worked for a number of years as a Petroleum Engineer in the disciplines of production engineering, reservoir engineering and P&FDD. He also has experience in gas operations as well as in well services assignments. Fowzi is results oriented and solution focused. He maintains collaborative working relationships with other Saudi Aramco organizations, different service companies and cross-functional colleagues, which allows him to guarantee full compliance and to effectively manage site operations, thereby ensuring that cost, quality, safety and project objectives are met in a timely and safe manner.

In 1999, Fowzi received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Adel S. Al-Thiyabi is a Shift Superintendent working in Saudi Aramco's Southern Area Well Completion Operations Department. He has 26 years of experience within Saudi Aramco, holding different positions, including working with Wireline and with Field Service and Well Completion. Adel previously held positions as an Operator, Senior Operator, Supervisor and Foreman.

Rifat Said has more than 20 years of experience in the oil and gas industry, specifically in cementing, coiled tubing operations and stimulation services, including matrix stimulation and fracturing. He worked for Schlumberger for 18 years before joining Saudi Aramco in September 2006. Currently, Rifat works as a Stimulation Engineer providing technical support to the Southern Area Production Engineering Department.

In 1986, he received his B.S. degree in Mechanical Engineering from the University of Indonesia, Jakarta, Indonesia.

Majid M. Rafie is a Field Production Engineer in Saudi Aramco's Southern Area Production Engineering Department. Before he joined Saudi Aramco, his experience included working with Baker Hughes in Houston, TX, as a Field Engineer for unconventional wells. Majid enjoys working on artificial lift techniques, such as electrical submersible pumps. He also is interested in the areas of multistage acid fracturing and matrix acidizing.

Majid participates in many Society of Petroleum Engineers (SPE) events and has published three SPE papers.

He received his B.S. degree in Petroleum Engineering from Texas A&M University, College Station, TX.

Mohammad Arifin is working in Schlumberger Saudi Arabia as the Coiled Tubing Services Technical Manager for the Kingdom of Saudi Arabia and the Kingdom of Bahrain. He joined Schlumberger in March 2000 and has had several assignments, including in Coiled Tubing Services, Stimulation and Cementing Services, and other segments in the oil field involving testing, wireline and artificial lift.

Mohammad has nearly 17 years of oil field experience, which covers a broad range of operations, including assignments offshore as well as in the desert, swamp and jungle. He also spent three years at the Schlumberger headquarters working in the Global Technical Support Group of InTouch, providing technical, operational and safety support for the worldwide operations.

Mohammad has coauthored several training modules for coiled tubing (CT) operations, Society of Petroleum Engineers (SPE) papers, and documentation of InTouch Best Practices.

He is currently involved in several joint projects between Schlumberger and Saudi Aramco where he uses his expertise in CT and stimulation.

In 2000, Mohammad received his B.S. degree in Chemical Engineering from Gadjah Mada University, Yogyakarta, Indonesia.

Kaisar Al Hamwi is a Sales & Account Manager for Schlumberger Coiled Tubing Services in Saudi Arabia's Southern Area. He is a Technical Engineer with more than 10 years of experience in the design, execution and evaluation of coiled tubing (CT) workover interventions in onshore environments, ensuring the highest service quality standards are followed.

Kaisar supports Saudi Aramco on the technical aspects of CT interventions in oil and power water injector wells for matrix stimulation, descaling, perforating, clean outs, milling, fishing, zonal isolation, etc. Prior to this assignment, he was the Field Service Manager for the 'Udhailiyah district, where he was responsible for service delivery and the introduction of new technologies for CT and matrix stimulation.

Kaisar started his career in Syria as a Field Engineer for Schlumberger Well Services, and he completed his field assignment in Saudi Arabia.

He has coauthored several Society of Petroleum Engineers (SPE) papers.

In 2007, Kaisar received his B.S.E. degree in Tele-Communication Engineering from the University of Damascus, Damascus, Syria.

Danish Ahmed has been working at Saudi Schlumberger since 2007. He is a Senior Intervention Optimization Engineer with Schlumberger Well Services – Coiled Tubing Services, supporting the ACTive Services Platform. Danish's experience includes working as a Field Engineer with Well Production Services (Fracturing and Pumping Services) based in 'Udhailiyah, Saudi Arabia, supporting proppant/acid fracturing and matrix acidizing jobs, followed by working as a Production Technologist with Petro Technical Services (formerly called Data and Consulting Services) in Dhahran, Saudi Arabia.

In 2007, he received his M.S. degree in Petroleum Engineering from Heriot-Watt University, Institute of Petroleum Engineering, Edinburgh, Scotland.

First Saudi Aramco Flow Line Scale Inspection in Ghawar Field Using a Robust IR Technology Offers a Reliable and Cost-Effective Approach

Abdullah A. Al-Ghamdi, Ibrahim M. El-Zefzafy and Abdallah A. Al-Mulhim

ABSTRACT

This article demonstrates the successful utilization, for the first time in Saudi Aramco's history, of infrared (IR) technology to detect scale adhesion to surface flow lines in the Ghawar field. As part of the Saudi Aramco asset integrity program, several field case studies are presented, highlighting a comprehensive evaluation of the technology and tool concept, field test results and equipment utilization guidelines. IR spectroscopy offers a means to study the interaction of IR light with matter to identify unknown material, which in this case is scale accumulation inside surface production lines.

Proof of concept tests were conducted in the field by visiting several wells and utilizing a thermal "infrared" gun pointed toward the production lines to observe the thermal transmission signature through different materials. All tests were conducted in conjunction with actual flow line dismantling to confirm the findings of the IR guns with respect to scale accumulation. The results from these field tests have confirmed that IR technology offers a robust, noninvasive and cost-effective approach to massive scale detection when compared to the existing practice of flow line dismantling. Comparing the thermal temperature profile of a healthy production line (base case) to those recorded from other lines has revealed that scale accumulation inside flow lines is associated with thermal signatures very different from that of the base case, indicating the presence of unknown materials in addition to production fluid and flow line material. It was found that scale buildup is generally linked to a dramatic decrease in the flow line and production manifold temperature. Temperature anomalies were shown to also be related to scale and/or debris accumulation.

This technology provides a smart and efficient tool for an asset integrity monitoring program. Scale accumulation has represented a great challenge for the petroleum industry to overcome and mitigate. It is linked to significant production decline and may lead to flow line blockage.

INTRODUCTION

Throughout history, scale deposition has represented a major challenge for the petroleum industry to overcome and mitigate. Scale accumulation is generally linked to significant production decline and flow line blockage, and it jeopardizes the integrity of production assets as it causes equipment wear and corrosion[1]. Flow restrictions due to scale translate into additional pressure drop across the production systems, especially near the upper completion section of the well, wellhead valves and flow line sections, both upstream and downstream of the surface chokes. In the oil field, scale can be found in many forms, including carbonate and sulfate salts of calcium, barium and strontium. The carbonate scale reaction is mainly caused by changes in temperature, while sulfate scales are generated for the most part from mixing incompatible waters[2]. Existing scale detection practices dictate the dismantling of surface production lines for scale inspection and detection once a production abnormality is detected.

These inspection operations are associated with downtime and cost, and are likely to be more and more necessary in light of the growing number of maturing wells. Earlier tests showed that the deployment of distributed temperature sensors can provide a means to predict reservoir accumulation once the system is integrated with the completion design itself[3]. This suggested that thermal imaging can be utilized as a means to detect solids accumulation, since these particles will tend to act as a heat insulation medium. As a result, an infrared (IR) based technique has been developed as a powerful, noninvasive means for investigating flow line maintenance performance.

This article describes the successful implementation of IR technology, for the first time in Saudi Aramco's history, to detect scale adhesion in surface flow lines in the Ghawar field by presenting several case studies highlighting a comprehensive evaluation of the technology and tool concept, field test results, and equipment utilization guidelines.

IR THERMAL IMAGING THEORY AND CONCEPT

Thermal imaging utilizes IR radiation to yield information about any abnormalities in the composition of a certain material when compared to a base model. This information can include changes in composition, temperature, moisture content, and degree of consolidation. The imaging is done through specially designed thermal imaging cameras and equipment that are able to measure temperature variation by quantifying the sent, detected, and emitted IR energy.

This equipment is usually integrated with computers running pre-programmed software to perform the analysis and produce thermal images of the object. This technology can be used to preserve asset maintenance integrity by detecting equipment corrosion in downstream facilities[4]. The idea was to capitalize on the potential of this technology as a technique for scale inspection. The operation itself was simple and only required a few personnel to take temperature readings near the well production manifold at different spots. These selected spots were near surface valves, joints and elbows, as well as at any other potential locations of flow restriction.

All temperature profiles were then compared to a base model containing a thermal image of the same spot in a healthy flow line. Anomalies in comparisons of the two temperature readings indicated abnormalities inside the flow line and generally were found to be related to scale and solids deposition. The thickness and uniformity of the scale was further linked to the profile shape. In general, these scale particles tend to act as insulators, thereby yielding a temperature value that is cooler than what is expected.

PROCESS DESCRIPTION

Being able to detect scale accumulation inside producing flow lines at an earlier stage can lead to cost savings by avoiding unnecessary spending on flow line replacement in the future. To explore this opportunity, the Production Engineering team performed a field trial test on four selected wells in Ghawar field with possible scaled up flow lines. IR cameras, Fig. 1, were utilized to measure flow line temperature based on emitted IR radiation. The tool specification can range from -4 °F to 2,192 °F.

The objective of the field trail test was to evaluate the feasibility of IR imaging as an approach to detect scale accumulation inside flow lines. In addition, the field operating and static conditions necessary to conduct the survey were evaluated. The guidelines, roles and responsibilities for field operators were established and are presented in Appendixes A and B. The technology implementation was conducted in parallel with actual flow line dismantling to confirm the results found with the IR cameras. The process was then repeated for each well at different locations. Figure 2 shows the field trial test process.

Fig. 1. IR camera.

While performing IR imaging at each location along the production manifold, as well as at other points of interest, thermal images were generated. These images were generally produced in different colors to indicate different temperature values based on the heat content of each type of material that the IR radiation encountered during the survey. In other words, the color intensity moving from purple to blue, blue to green, green to yellow, and yellow to red is an indication of increasing temperature values. Moreover, the red and yellow colored parts of the images indicate warmer sections of the flow line while the purple and blue colored parts show cooler sections.

FIELD TRIAL SURVEILLANCE RESULTS

The previously discussed process was conducted on four wells in the southern area of the Ghawar field to trial test the technology for the first time in Saudi Aramco. In each case study discussed next, a brief history of the well is provided before discussing the IR imaging survey findings and comparing them with the results of a visual inspection.

Well-A Case Study

Well-A is a vertical perforated oil producer completed back in 1998. The well has been producing nearly 4,000 barrels per day (BPD) most of its production life with rising water cut. A scale inhibitor squeeze was performed on this well, and well-

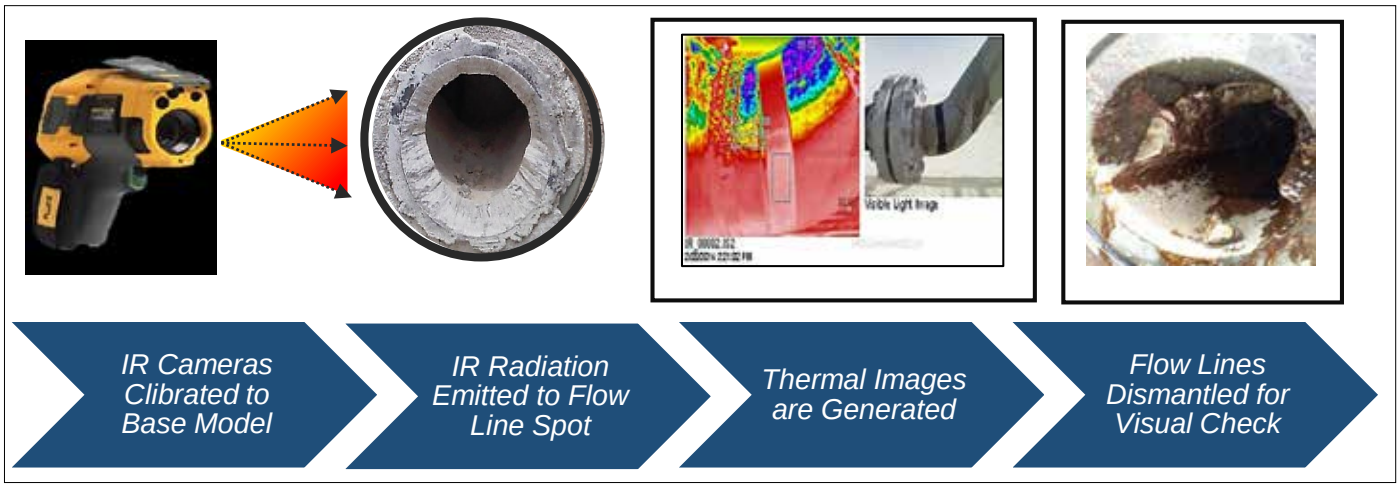

Fig. 2. Field inspection via IR thermal imaging: The process workflow for field trials.

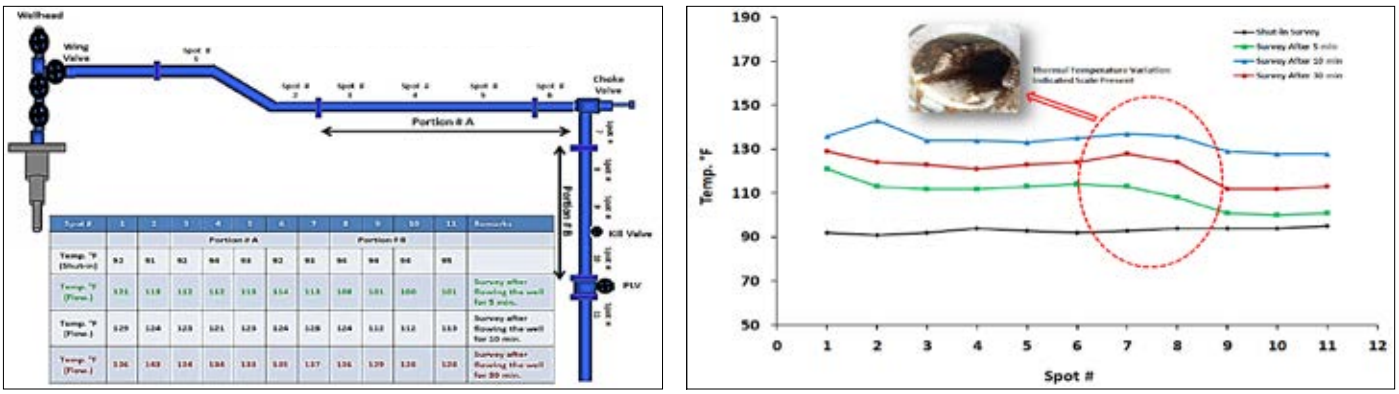

Fig. 3. IR imaging survey at different spots along the production manifold of Well-A (top). Data were plotted after the different times of the production period to indicate anomalies, if any (bottom).

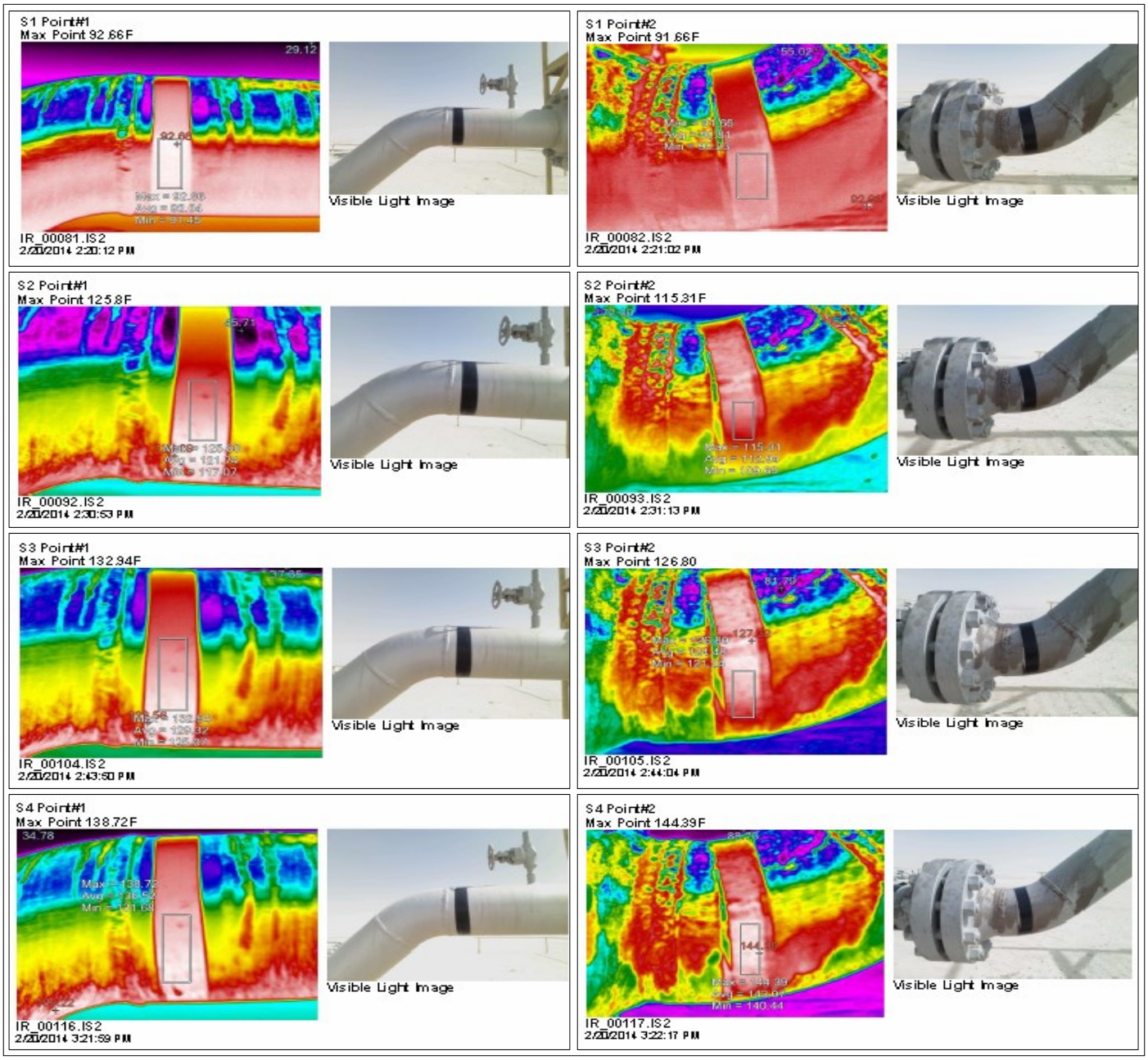

Fig. 4. Thermal images of the production manifold for Well-A at spots #1 (left) and #2 (right), portion A. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

bore drifting was conducted to ensure no flow restriction in the completion. A dramatic decrease in the total production rate — from 3,500 BPD to 500 BPD — was reported in 2014 with an increase in flowing wellhead pressure (FWHP), which suggested scale buildup. The following steps summarize the operational highlights of the IR survey conducted on Well-A, Fig. 3:

1. The well was shut-in for more than 24 hours before the survey.
2. The survey was conducted in the early morning at 7:30 a.m.
3. The well manifold was surveyed under shut-in conditions with an average manifold temperature of 93 °F.
4. The well was opened to the production line on a fully open choke for 5 minutes with a flowing wellhead temperature (FWHT) of 121 °F, then shut-in to run the IR thermal imaging survey. The survey results follow:
   - A +/- 5 °F (minor and/or negligible) temperature variation was observed before — 113 °F — and after — 108 °F — the choke valve, which confirmed that the choke valve was free of scale.
   - A +/- 12 °F (major) change in temperature was observed after the plot limit value (PLV) — 101 °F — compared with portion A's average temperature — 113 °F — which confirmed the presence of scale.
   - A +/- 8 °F (moderate) temperature variation along portion B indicated possible scale precipitation.
5. The well was opened to the production line on a fully open choke for 10 min with a FWHT of 129 °F, and then shut-in to run the IR thermal imaging survey. The survey results follow:
   - Generally, the temperature of the manifold, both portions A and B, was heated, and a temperature variation

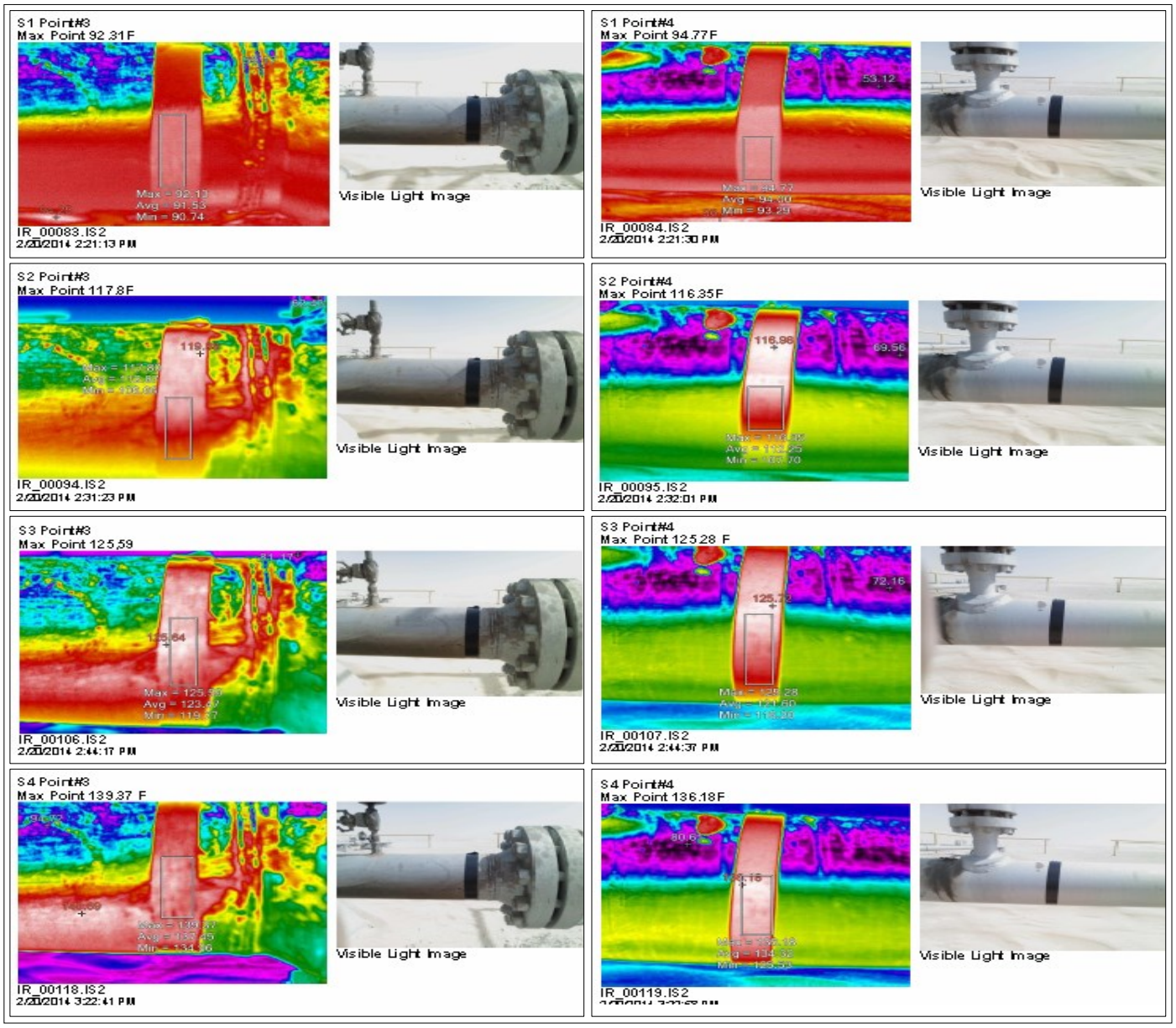

Fig. 5. Thermal images of the production manifold for Well-A at spots #3 (left) and #4 (right), portion A. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

— +/- 10 °F — was observed after the PLV compared with the temperature of portion A.

- Along portion B, a temperature variation of +/- 11 °F persisted.

6. The well was opened to the production line at full choke for 30 minutes with a FWHT of 136 °F, and then shut-in to run the IR thermal imaging survey. The survey results follow:
   - Generally, the temperature of the manifold, both portions A and B, was heated more, as the well flowed for more time; however, the temperature variation of +/- 5 °F after the PLV compared to the average temperature of portion A was reduced.

Results from both IR imaging and visual checks were consistent with each other and in agreement, Fig. 3. Thermal images, provided in Figs. 4, 5 and 6, indicated that scale was found to be mainly accumulating downstream of the PLV.

Well-B Case Study

Well-B is a vertical open hole oil producer drilled in 1977 and recompleted in 2007 to sidetrack the well and eliminate possible downhole communication. The well was treated with a scale inhibitor squeeze in 2010 and showed no scale buildup during normal routine inspection. When wireline gauging was performed in 2014, it was difficult to pass the wireline through due to wellbore restrictions. Well production was reported to fluctuate and fell slightly — by 200 BPD — at the same choke setting with an increase in FWHP. The following steps summarize the operational highlights of the IR survey conducted on Well-B, Fig. 7:

1. The well was shut-in for more than 24 hours before the survey.

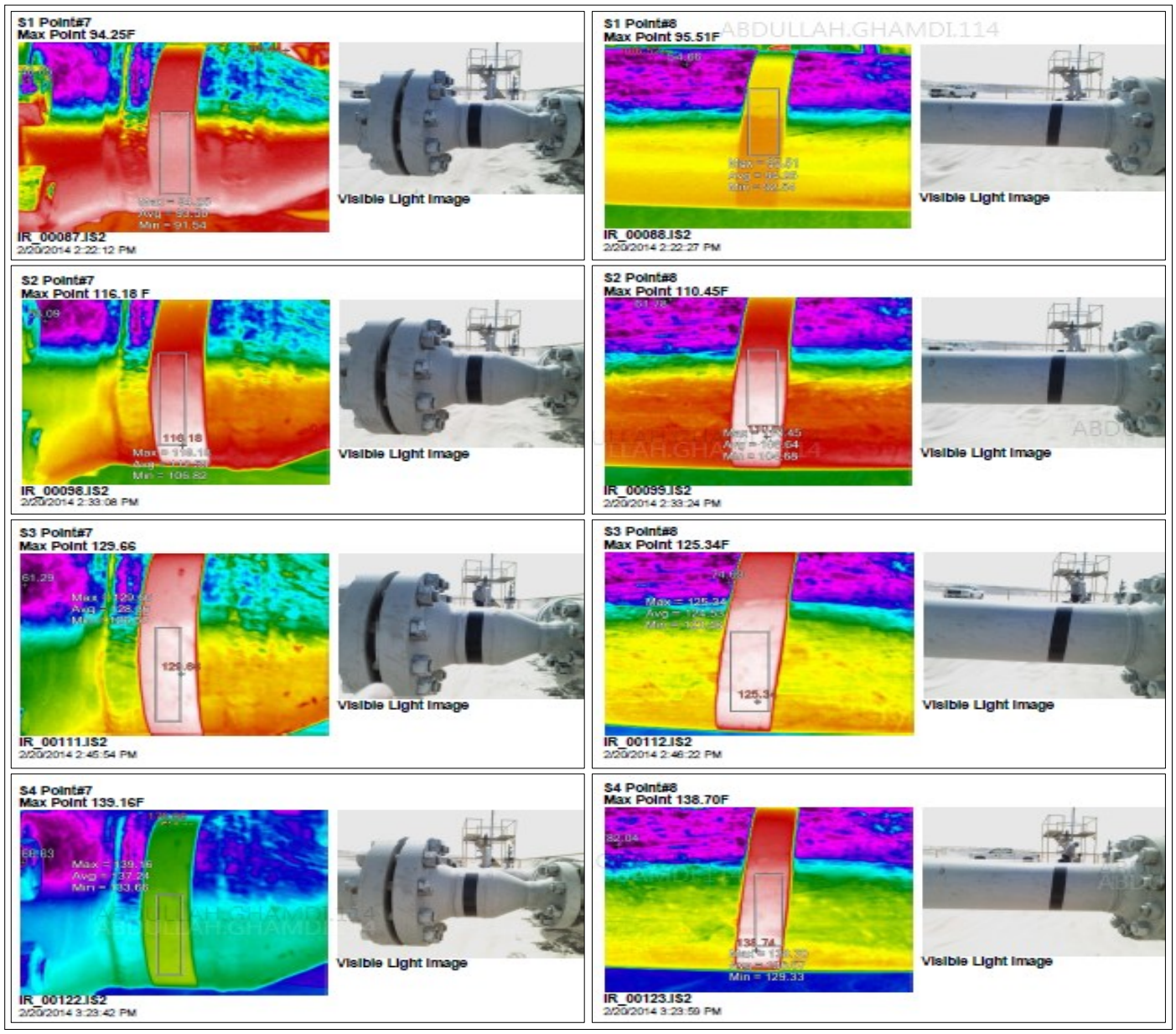

Fig. 6. Thermal images of the production manifold for Well-A at spots #7 (left) and #8 (right), portion B. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

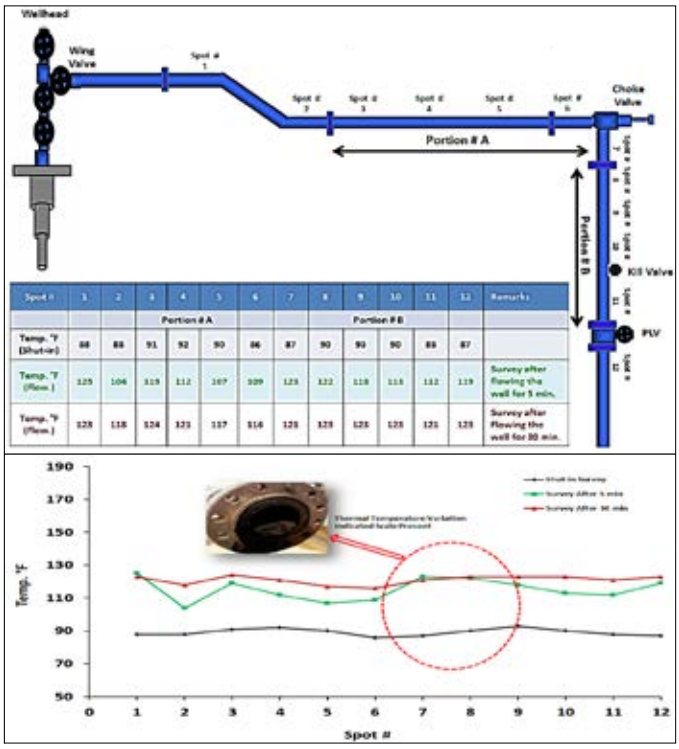

Fig. 7. IR imaging survey at different spots along the production manifold of Well-B (top). Data were plotted after the different times of the production period to indicate anomalies, if any (bottom).

2. The survey was conducted in the morning at 9:30 a.m.
3. The well manifold was surveyed under shut-in conditions with an average manifold temperature of 90 °F.
4. The well was opened to the production line on a fully open choke for 5 minutes with a FWHT of 125 °F, and then shut-in to run the IR thermal imaging survey. The survey results follow:
   - A dramatic temperature decrease — +/- 12 °F — was observed in portion A, from 119 °F to 112 °F to 107 °F, which suggested debris precipitation.
   - The manifold temperature (after the choke) warmed up again and reported 123 °F, which indicated that the manifold after the choke valve was free of scale.
   - A +/- 3 °F (minor and/or negligible) temperature variation was observed after the choke valve — 122 °F — compared to a temperature of 119 °F after the PLV, which confirmed that portion B and the PLV were free of scales.
5. The well was opened to the production line at full choke for 30 minutes, and then shut-in to run the IR thermal imaging survey. The survey results follow:
   - Generally, the manifold's temperature, both portions A and B, was heated, and a dramatic temperature decrease — +/- 7 °F — was observed in portion A, from 124 °F

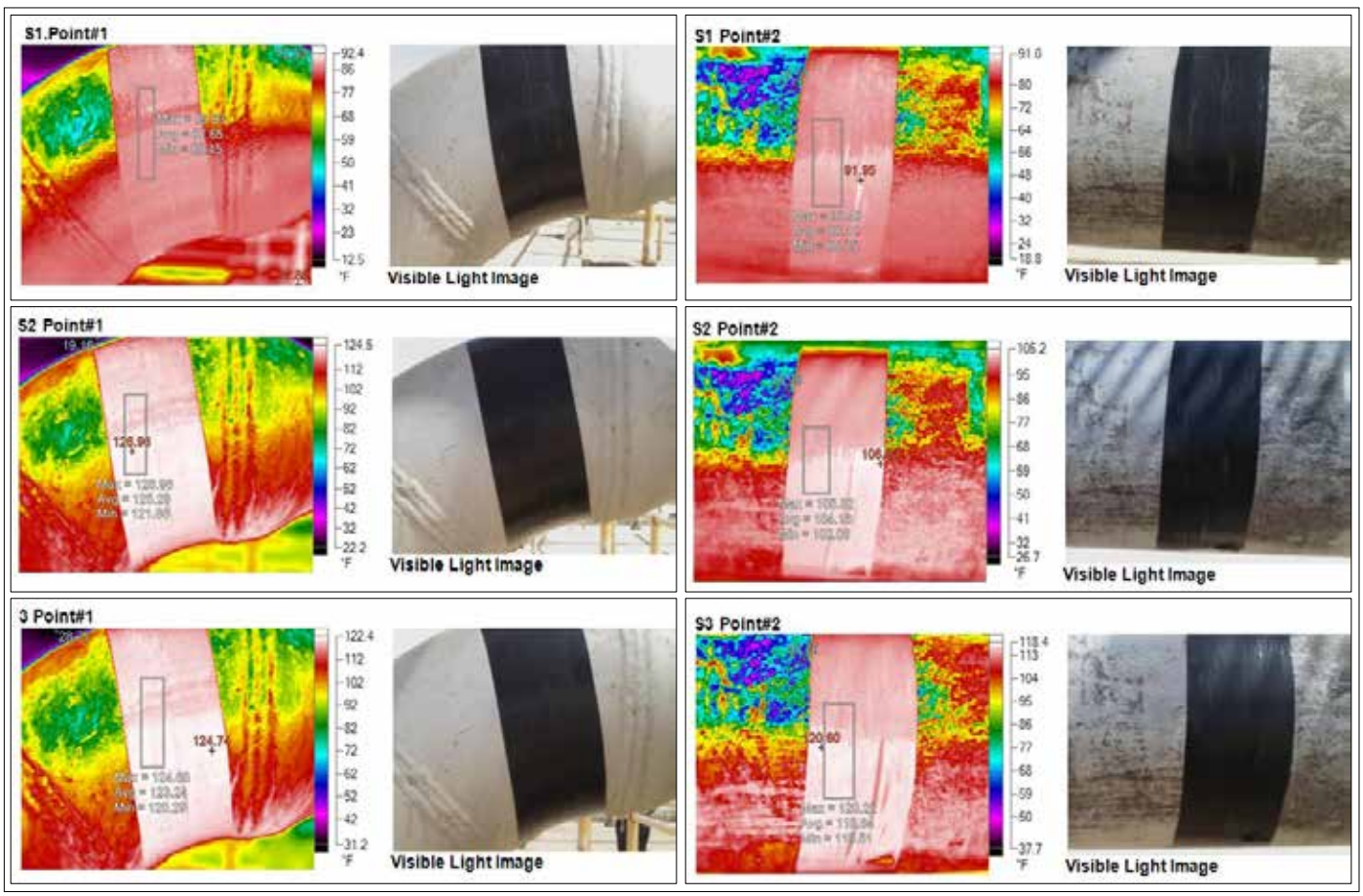

Fig. 8. Thermal images of the production manifold for Well-B at spots #1 (left) and #2 (right), portion A. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

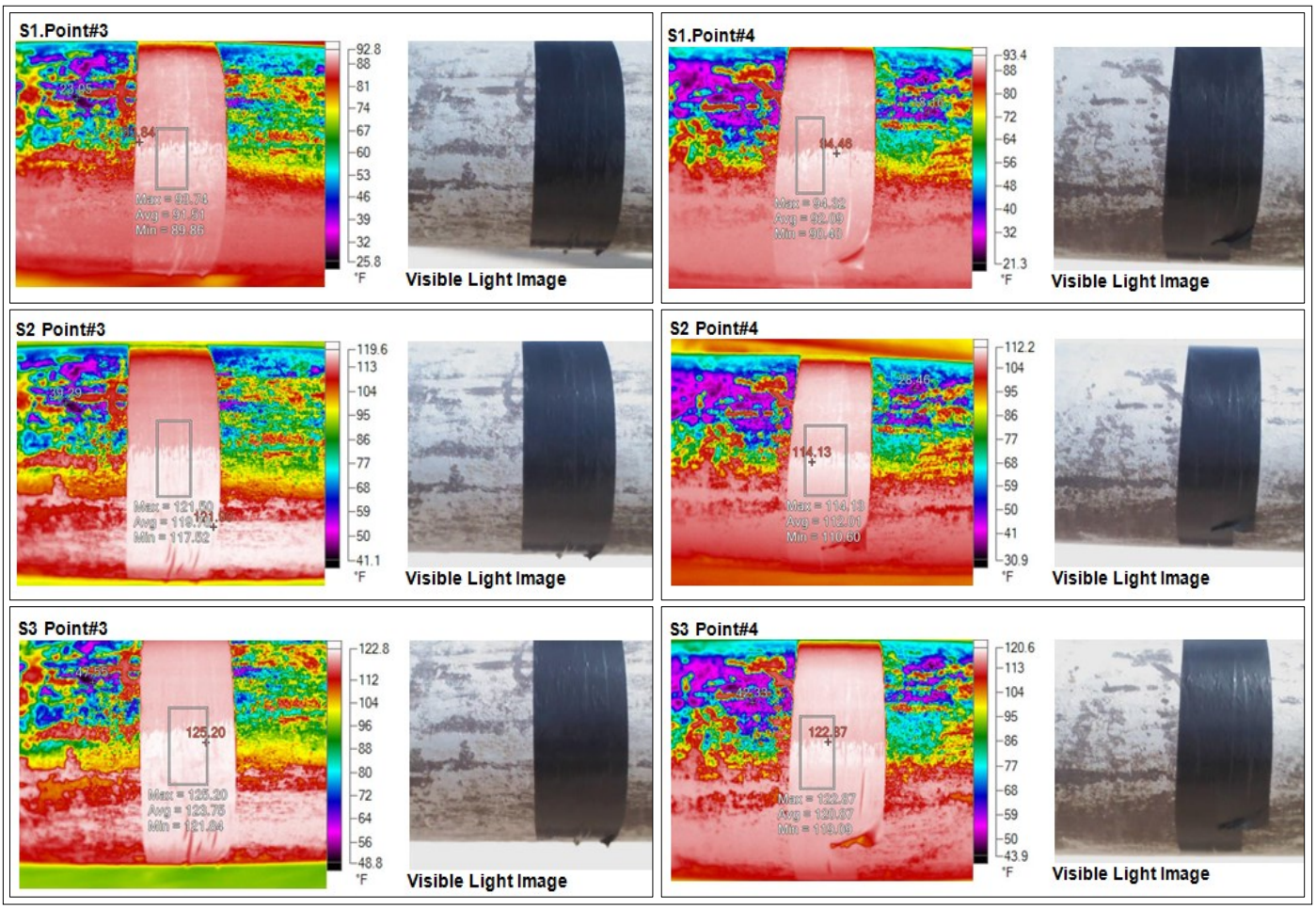

Fig. 9. Thermal images of the production manifold for Well-B at spots #3 (left) and #4 (right), portion A. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

to 121 °F to 117 °F, which confirmed the presence of debris.

- The manifold temperature (after the choke) was warmed up again and reported 123 °F, which indicated that the manifold after the choke valve was free of scales.
- A +/- 2 °F (minor and/or negligible) temperature variation was observed after the choke valve — 123 °F — compared with the temperature of 121 °F after the PLV, which confirmed that portion B and the PLV were free of scales.

The results from both the IR imaging and visual check were consistent and in agreement, Fig. 7. Thermal images, provided in Figs. 8, 9 and 10, indicated that solids and scale fragments were mainly found upstream of the surface choke.

Well-C Case Study

Well-C was drilled as a vertical open hole oil producer in 1995. The well generally maintained an excellent production level and was treated for scale in 2000. Throughout recent years, wireline drifting to gauge the well usually encountered difficulties across the wellhead and the upper completion section. This led to a scale inspection investigation utilizing IR thermal imaging. The following steps summarize the operational highlights of the IR survey conducted on Well-C, Fig. 11:

1. The well was shut-in for more than 24 hours before the survey.
2. The survey was conducted at noon.
3. The well manifold was surveyed under shut-in conditions with an average manifold temperature of 114 °F.
4. The well was opened to the production line on a fully open choke for 15 minutes with a FWHT of 140 °F, and then shut-in to run the IR thermal imaging survey. The survey results follow:
   - A +/- 4 °F (minor and/or negligible) temperature variation was observed along the manifold, which confirmed that the manifold, both portions A and B, was free of scale.

The results from both the IR imaging and visual check were consistent and in agreement, Fig. 11. Thermal images, provided in Figs. 12, 13 and 14, indicated that no scale was found along the production manifold for this well, and a well downhole descaling operation was designed.

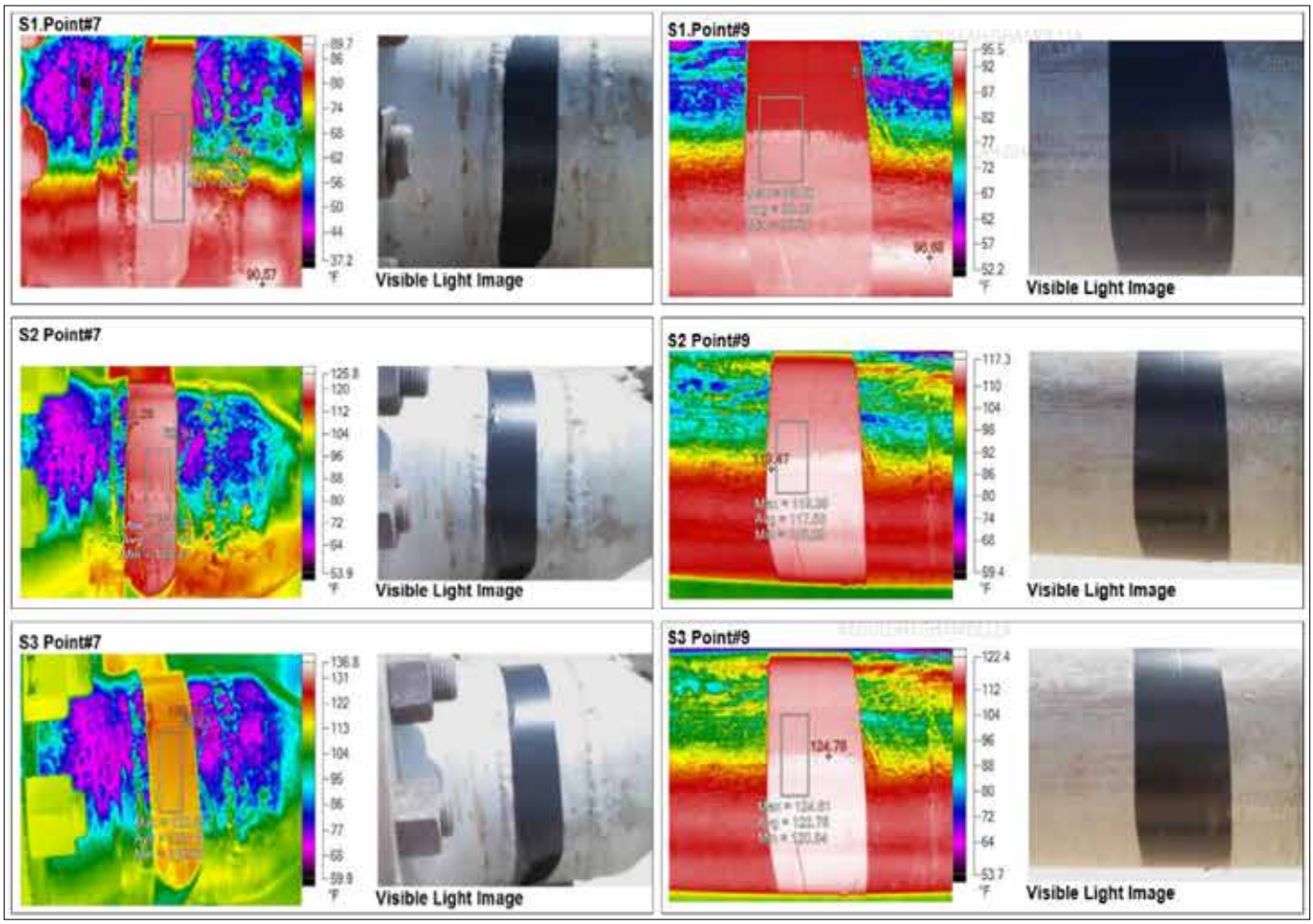

Fig. 10. Thermal images of the production manifold for Well-B at spots #7 (left) and #9 (right), portion B. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

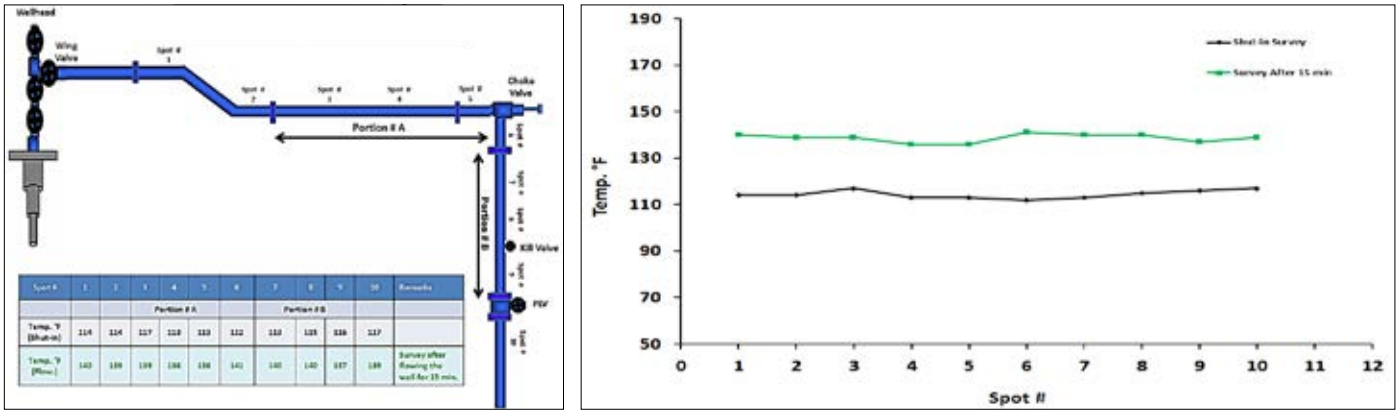

Fig. 11. IR imaging survey at different spots along the production manifold of Well-C (top). Data were plotted after 15 minutes of production to indicate anomalies, if any (bottom).

Well-D Case Study

Well-D was drilled as a vertical open hole oil producer in 2007. The well was treated with a scale inhibitor treatment one year later. The well was worked over to eliminate a well integrity issue related to zonal communication in February 2014. After that, the well experienced high FWHP against a fully open choke and downstream valves, which dictated that the production operators investigate the manifold for scale buildup. The following steps summarize the operational highlights of the IR survey conducted on Well-D, Fig. 15:

1. The well was shut-in for more than 24 hours before the survey.
2. The survey was conducted in the morning at 9:30 a.m.
3. The well manifold was surveyed under shut-in conditions with an average manifold temperature of 107 °F.
4. The well was opened to the production line on a fully open

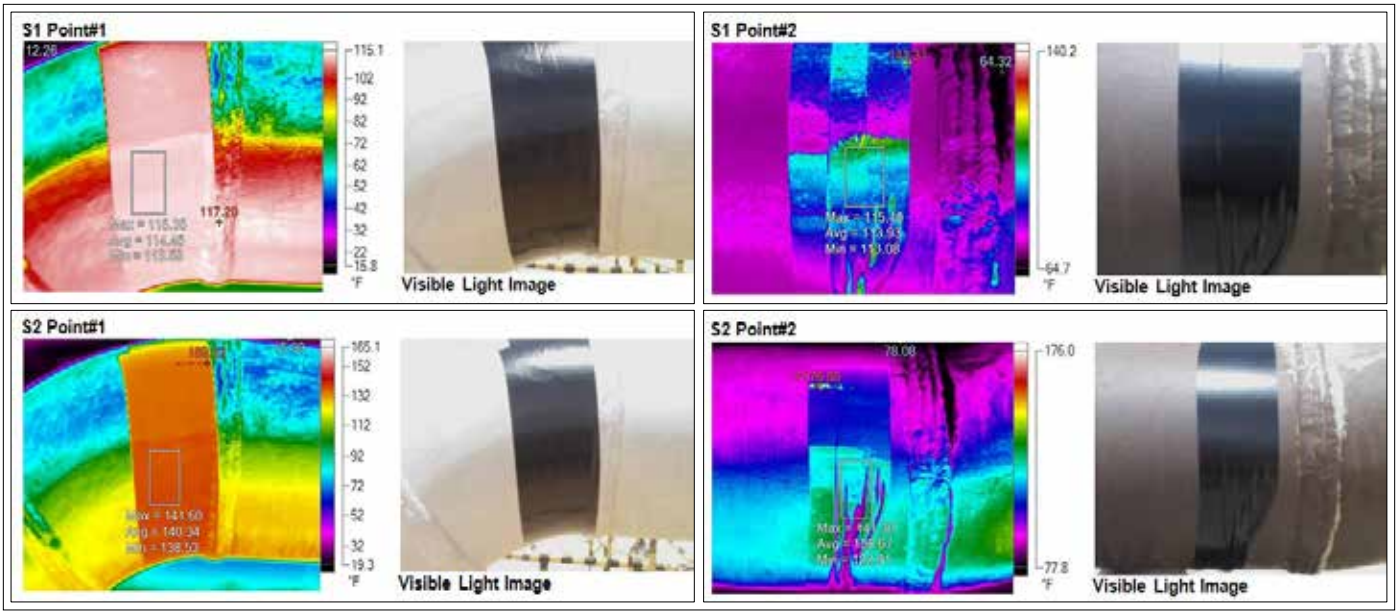

Fig. 12. Thermal images of the production manifold for Well-C at spots #1 (left) and #2 (right). The color variation is an indication of the temperature value that could be related to the produced phase heat content.

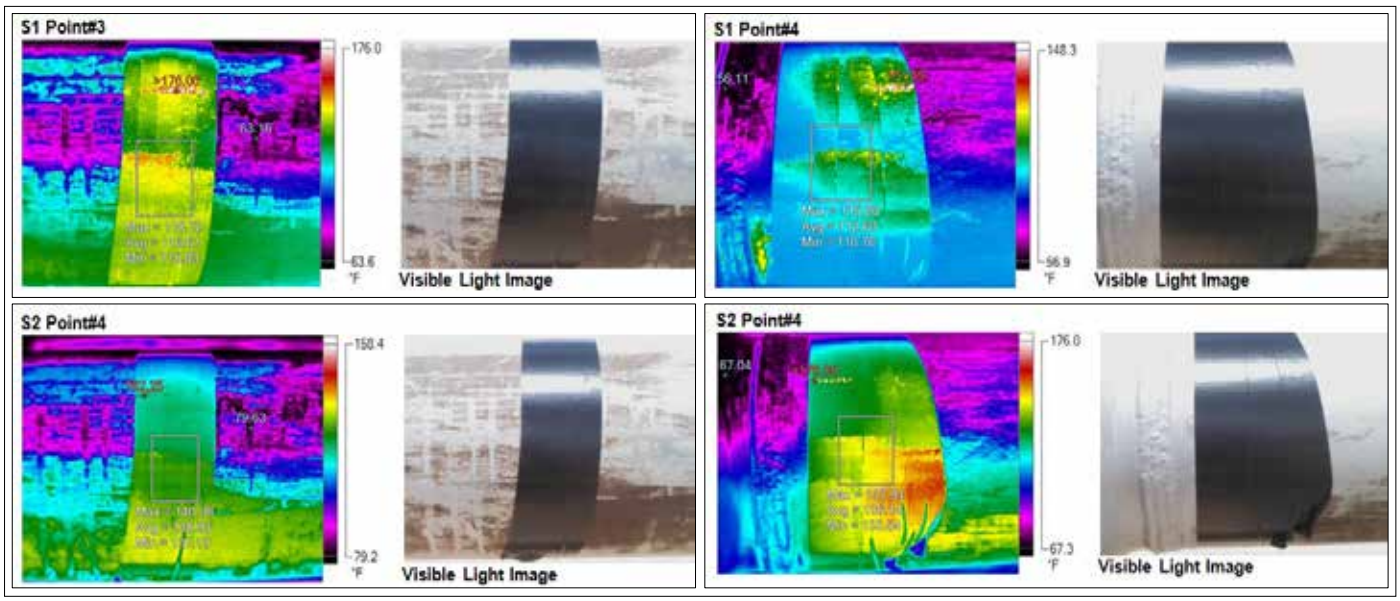

Fig. 13. Thermal images of the production manifold for Well-C at spots #3 (left) and #4 (right). The color variation is an indication of the temperature value that could be related to the produced phase heat content.

choke for 5 minutes. The survey results follow:

- A cooling effect was reported along the manifold in portions A and B, which suggested either scale precipitation along the manifold and/or that the well was producing at a high gas rate.
- The decision was made to flow the well for 30 minutes.

5. The well was opened to the production line on a fully open choke valve for 30 minutes, then shut-in to run the IR thermal imaging survey. The survey results follow:
   - Temperature variations along the manifold were reported in portions A and B and confirmed the presence of scale along the manifold.

The results from both the IR imaging and visual check were consistent with each other and in agreement, Fig. 15. Thermal images, provided in Figs. 16, 17, 18 and 19, indicated that scale buildup was found along the production manifold for this well, especially downstream of the surface choke.

CONCLUSIONS AND THE WAY FORWARD

Results obtained from these case studies indicated the potential of utilizing IR thermal imaging for asset integrity monitoring in upstream oil and gas operations, especially for scale monitoring. This work resulted in the following conclusions:

1. Utilizing IR thermal cameras has produced results consis-

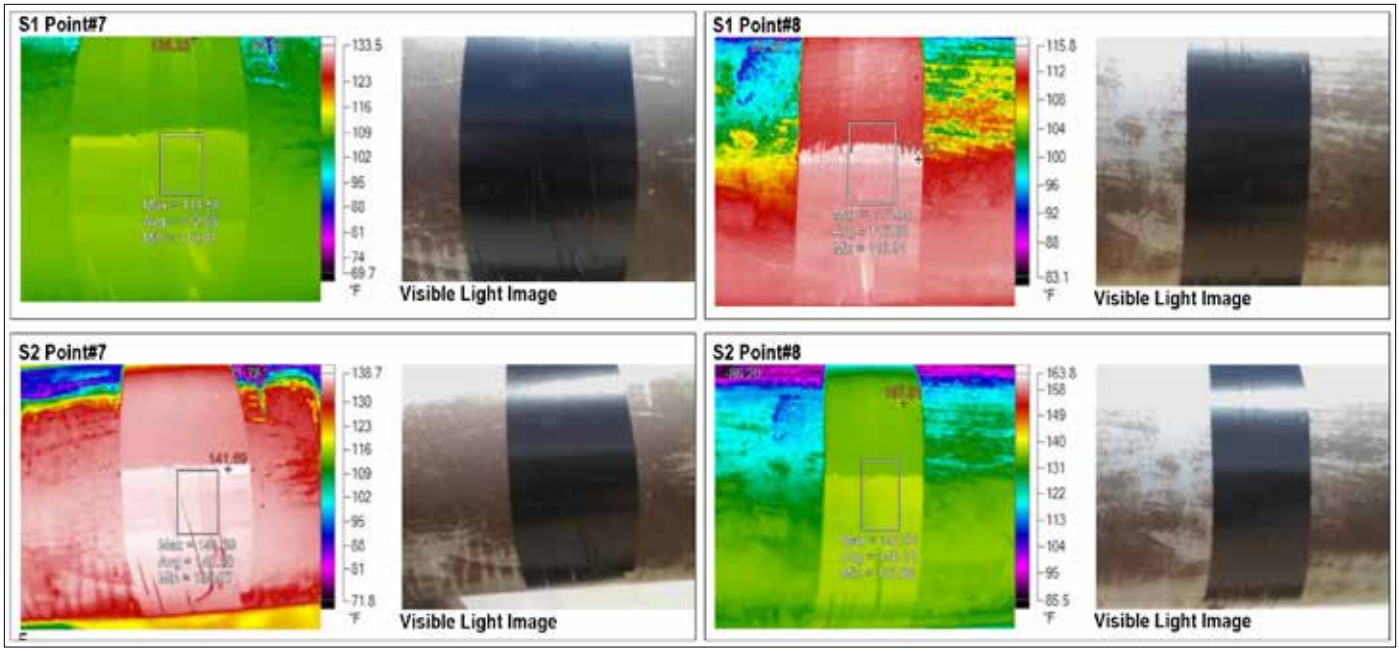

Fig. 14. Thermal images of the production manifold for Well-C at spots #7 (left) and #8 (right), portion B. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

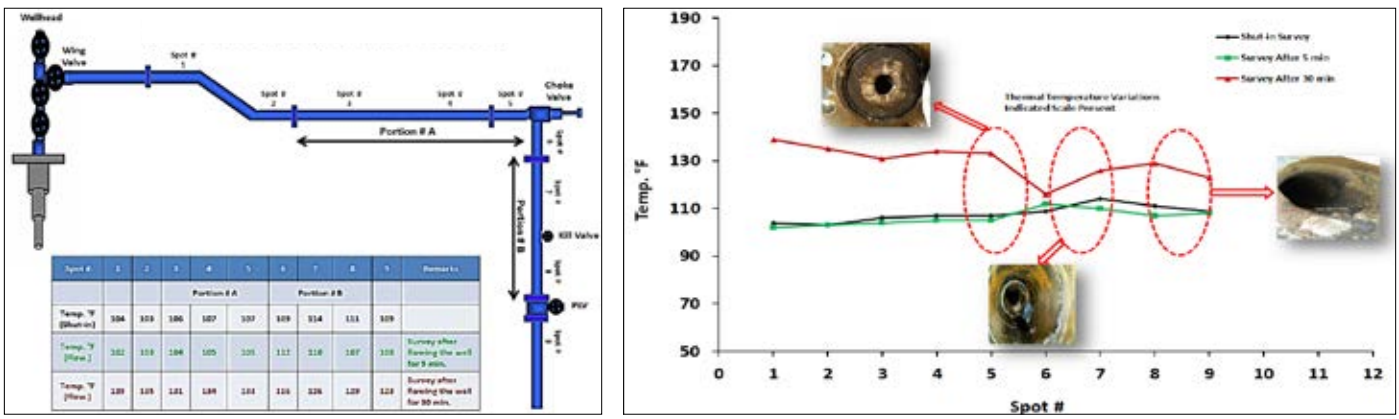

Fig. 15. IR imaging survey at different spots along the production manifold of Well-D (top). Data were plotted after the different times of the production period to indicate any anomalies, if any (bottom).

tent with those of visual inspection in terms of detecting scale accumulation.

2. An IR thermal imaging survey was confirmed to be a satisfactory noninvasive scale inspection technique at a reduced overall operational cost as it requires no flow line dismantling.
3. Scale was found to be correlated with a dramatic decrease in temperature as well as a fluctuation in the temperature profile when compared with established base cases.
4. Thin scale accumulation as well as dirty spots were found to mislead the interpretation of thermal imaging.
5. Flow line dismantling was required to identify and collect scale samples.
6. Ongoing work is taking place to analyze thermal signature signals to correlate them to fluid type as well as to scale type so as to avoid the need for flow line dismantling.

ACKNOWLEDGMENTS

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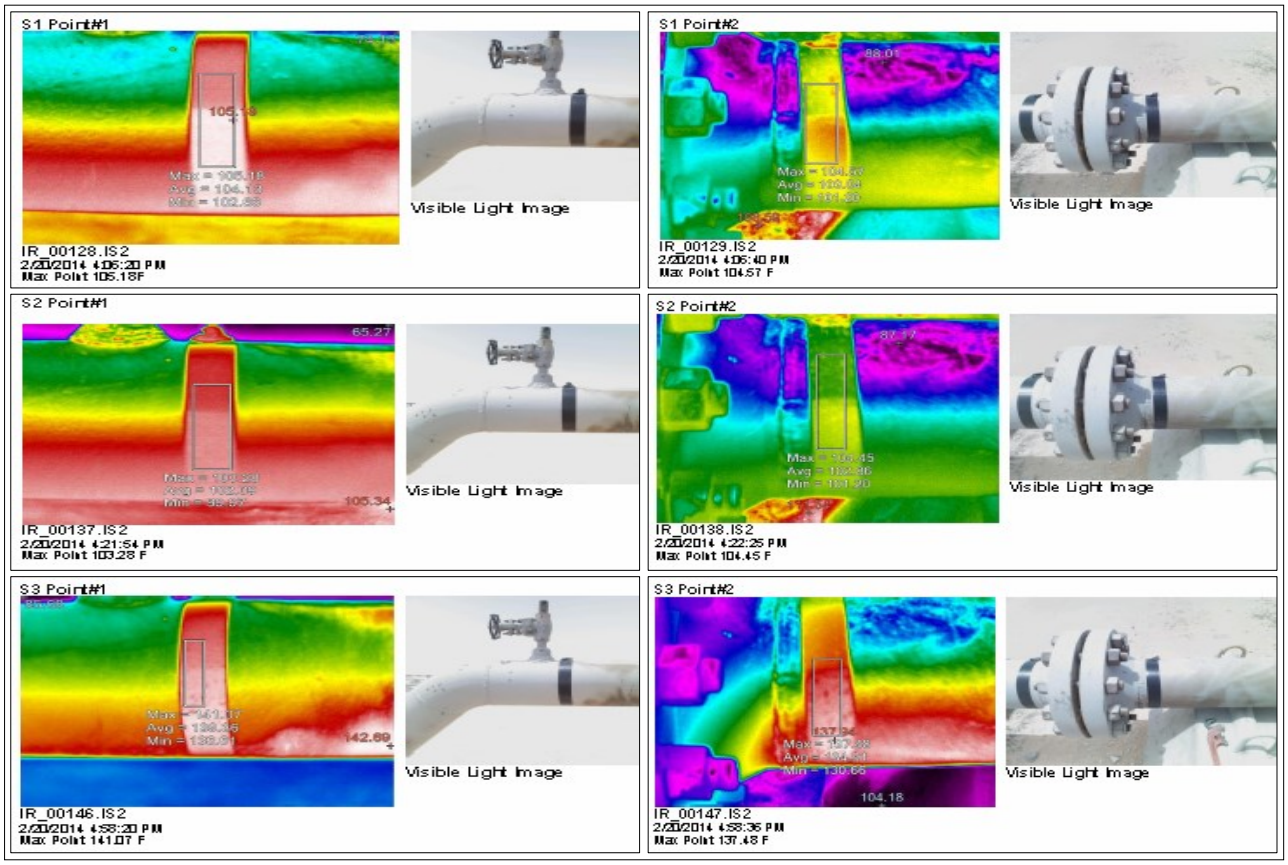

Fig. 16. Thermal images of the production manifold for Well-D at spots #1 (left) and #2 (right). The color variation is an indication of the temperature value that could be related to the produced phase heat content.

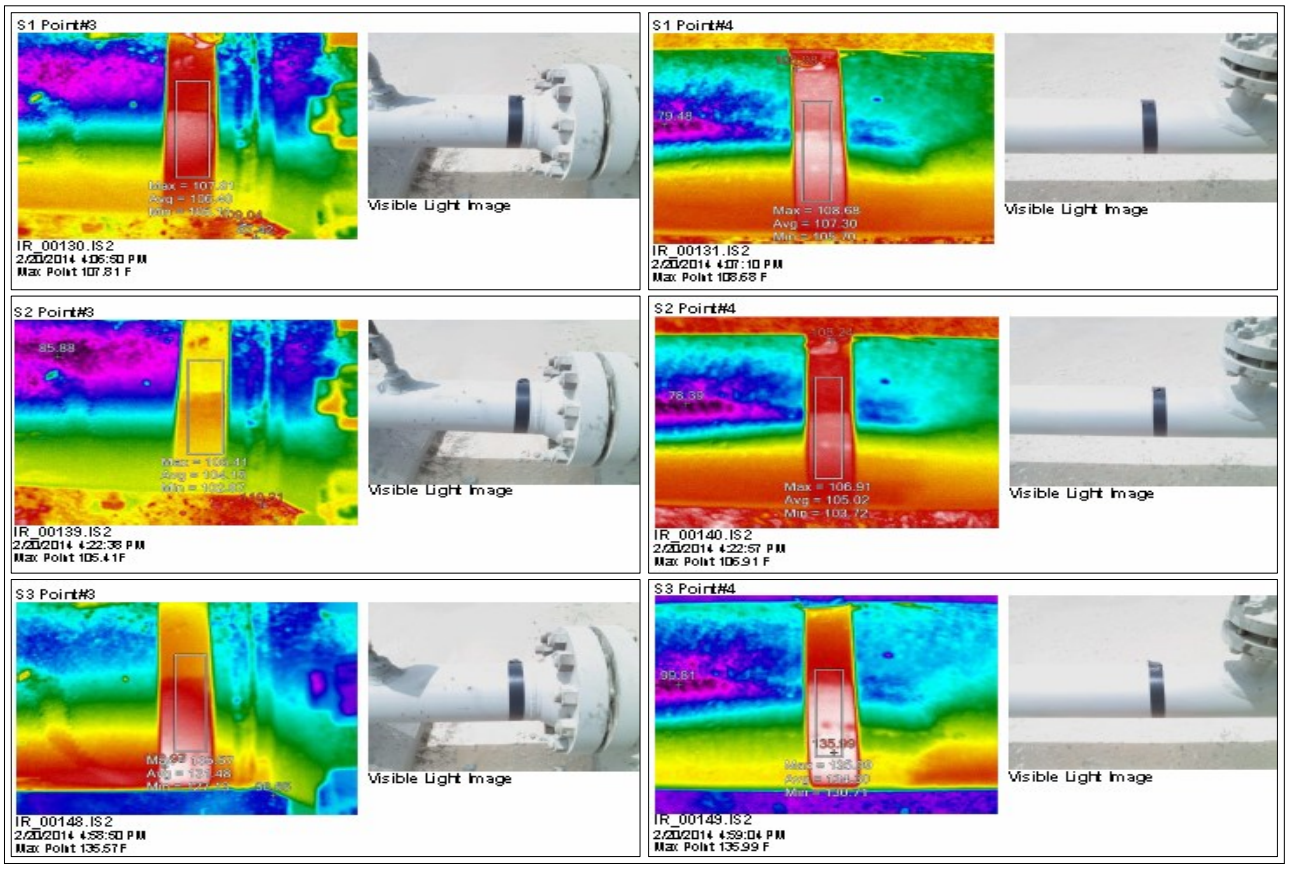

Fig. 17. Thermal images of the production manifold for Well-D at spots #3 (left) and #4 (right). The color variation is an indication of the temperature value that could be related to the produced phase heat content.

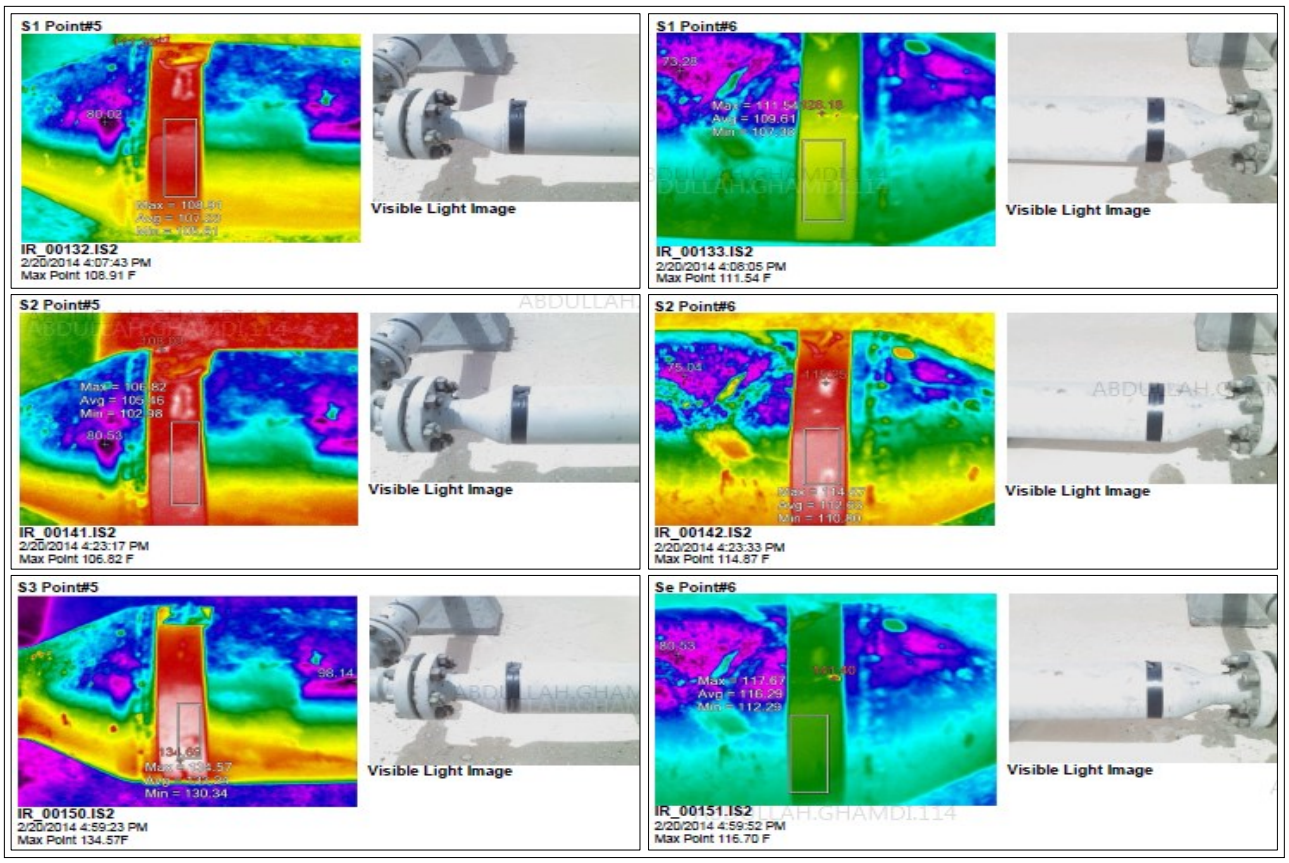

Fig. 18. Thermal images of the production manifold for Well-D at spots #5 (left) and #6 (right). The color variation is an indication of the temperature value that could be related to the produced phase heat content.

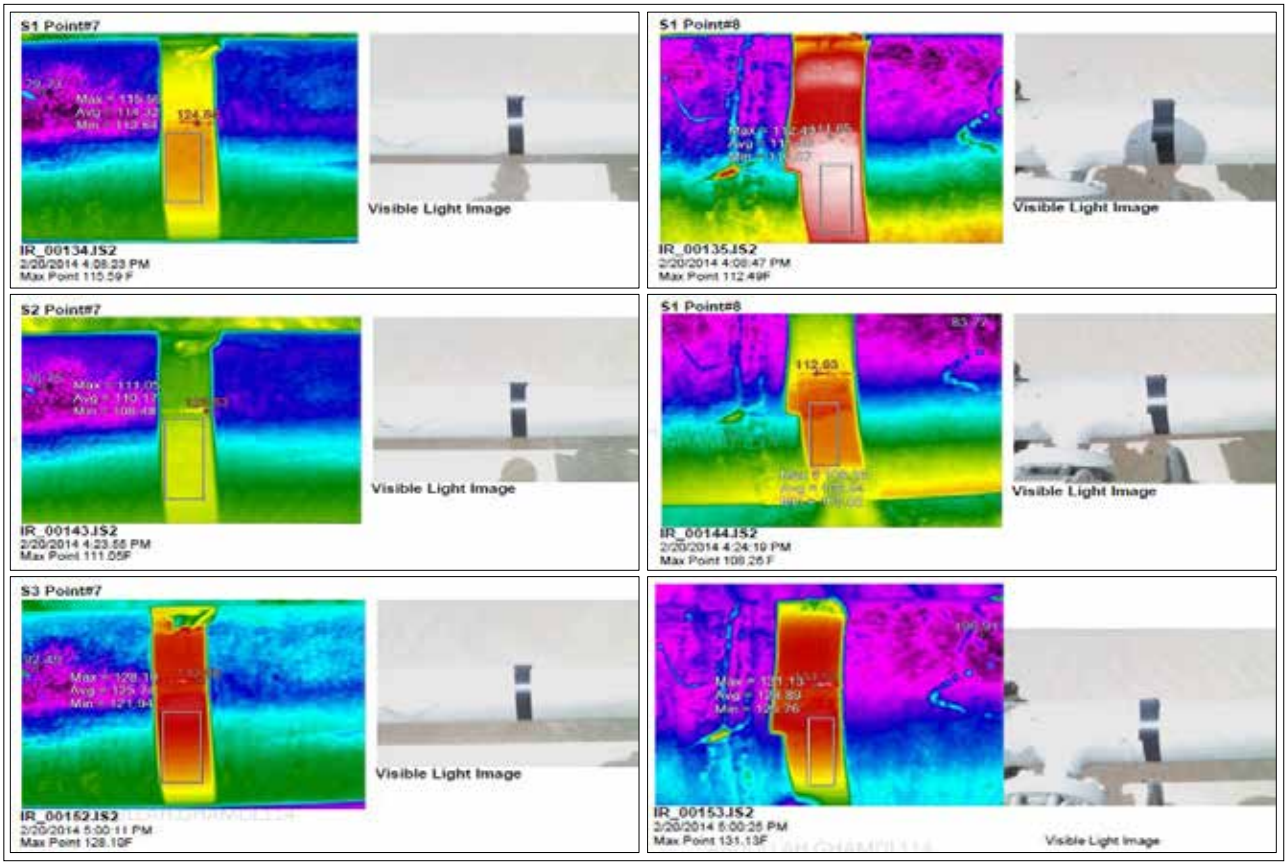

Fig. 19. Thermal images of the production manifold for Well-D at spots #7 (left) and #8 (right), portion B. The color variation is an indication of the temperature value that could be related to the produced phase heat content.

Appendix A (IR Thermal Imaging Survey Guidelines)

Objectives

Use the handy IR thermal imaging gauge to find any evidence of scale inside the manifold, choke valve, PLV and flow line. Record all measurements on the as-built diagram.

Visit Guidelines

Here are some guidelines to follow when performing an IR thermal imaging survey. Please review these before going out to a field.

Pre-Job Requirement

1. Before the visit, the Production Engineer communicates with the gas-oil separation plant (GOSP) foreman and operators of the concerned well to be shut-in at least for 24 hours before the survey.
2. Take the following with you to the field: As-built diagram for the manifold and flow line, IR thermal imaging equipment, pressure gauge, personal protective equipment (PPE) and a clipboard to help hold the as-built diagram in the wind.

Procedures

1. The test should be conducted in the morning (as early as possible) and while the inspector is at the well site. The concerned well is opened to begin flowing. After flowing the well for 5 minutes, run the required survey — the survey should be run under flowing conditions. It is preferable to re-run the survey after 15 and 30 minutes.
2. It is preferable to have two people conduct the survey (one to take readings and the other to record them), but it is not mandatory. With windy and dusty conditions, it is too slow to do both with only one person.
3. Locate all pressure measurement points from the wellhead to the PLV. Attempt to measure the pressure drop between the well and the PLV. Use the same calibrated pressure gauge for all measurements to avoid any reading errors.
4. Measure the temperature of the wellhead and of the manifold, before and after the choke valve, all the way to the PLV at every meter, or as required.
5. Record all temperature and pressure measurements on the as-built diagram.
6. Assess all the readings and take the following actions as needed: If the selected area of the manifold, choke valve, etc., is greasy or dirty, scrape off the dirt before taking the measurement, as the dirt acts as an insulator and you will

Date	Well	GOSP	Choke Setting	Up/Down Reading (psi)	Up/Down Reading at Full Choke (psi)	Temp (°F)	Remarks Location of Reading

Table 1. Required information for conducting the IR thermal imaging survey

collect a misleading temperature. Take temperature measurements every foot and mark them on the as-built diagram starting from the wing valve. Ensure that a temperature reading is taken on either side of the flanges, valves and elbows. Follow the fluid flow, searching for any cool spots where scale inside the pipe may be acting as an insulator.

7. After the IR thermal imaging survey job, examine the differential pressure across the fully open choke valve. Use the attached format presented in Appendix B, to document the results.

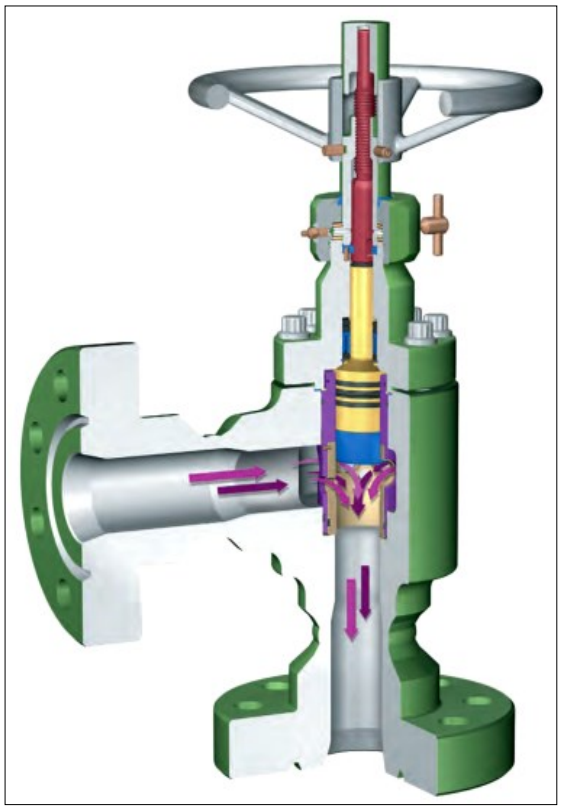

Fig. 20. A diagram of the choke valve.

Appendix B (Examining Pressure Differential across the Fully Open Choke)

Procedures

1. Notify the GOSP foreman and report the job type ahead of time.
2. The GOSP field operator should report the existing choke valve, Fig. 20, setting.
3. Report the upstream and downstream pressure of the choke valve.
4. Open the choke valve to the fully open position.
5. Wait for 30 minutes to have the well in a stabilized condition.
6. Report the upstream and downstream pressure of the choke valve.
7. Restrict the well back to its original choke setting.
8. Compile the data in Table 1 to be sent back to the engineer.

Note: The GOSP operator should highlight the choke valve conditions (loose, hard to operate, stuck, etc.).

BIOGRAPHIES

Abdullah A. Al-Ghamdi is a Petroleum Engineer assigned to work as a Production Engineer for Saudi Aramco's Southern Area Production Engineering Department's South Ghawar Division. He has 6 years of experience and has been covering many technical operational specialties, including intelligent field applications, smart well completions, production optimization through water management and well integrity solutions related to scale and corrosion management.

Abdullah has published many technical reports on intelligent field reliability, scale studies, nanoparticle applications in the oil and gas industry, and effective business strategies for energy production organizations.

He received his B.S. degree in Petroleum Engineering from Louisiana State University, Baton Rouge, LA, and his M.S. degree in Petroleum Engineering from the University of Texas at Austin, Austin, TX.

Ibrahim M. El-Zefzafy is a Senior Petroleum Engineer with Saudi Aramco's South Ghawar Production Engineering Division of the Southern Area Production Engineering Department. He has 22 years of experience in the oil and gas industry in rigless well intervention, oil artificial lift design, well performance and production optimization, well completion and testing, and workover interventions. Ibrahim also has comprehensive well services and production enhancement experience in onshore and offshore operations.

Since joining Saudi Aramco in 2006, he has been involved in a wide variety of technical projects and planning activities as part of oil development and enhanced oil recovery projects. Ibrahim manages a team responsible for the introduction and implementation of new technology applications, including developing engineered solutions to improve productivity, in collaboration with Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC) and the Research and Development Center (R&DC).

Prior to joining Saudi Aramco, he worked as a District Production Engineer with Gulf of Suez Petroleum Company's joint venture with British Petroleum in Egypt.

Ibrahim is a registered member of the Society of Petroleum Engineers (SPE), and he has authored and coauthored numerous SPE papers.

In 1995, Ibrahim received his B.S. degree in Petroleum Engineering from Al-Azhar University, Cairo, Egypt.

Abdallah A. Al-Mulhim is currently working as the acting Oil Production Engineering General Supervisor in Saudi Aramco's Southern Area Production Engineering Department. His experience includes work in various petroleum engineering departments as a Well Log Analyst, Geosteering MWD/LWD Engineer, Petrophysicist, Oil and Gas Production Engineer, and Fracturing and Acid Stimulation Specialist.

In 2002, Abdullah received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia. In 2008, he received his M.S. degree in Petroleum Engineering – Petrophysics from the Colorado School of Mines, Golden, CO.

Technical and Strategic Approaches for CO_2 Management in Refining Businesses

Dr. Kosan Roh, Hyungmuk Lim, Haeun Yoo, Hasan Imran, Ali S. Al-Hunaidy and Dr. Jay H. Lee

ABSTRACT

Carbon dioxide (CO_2) management in petroleum refining businesses should be a crucial topic for discussion due to the demand from different sectors for businesses to reduce their CO_2 emissions to the atmosphere. Since refineries typically have a large number of CO_2 emission sources, various CO_2 reduction strategies can be applied in the effort to reduce, mitigate or utilize the emitted CO_2. In this article, the CO_2 emission sources of a Middle East refinery utilizing Arab Heavy and Arab Medium crude oil are analyzed, and two promising CO_2 reduction strategies are discussed: The production of valuable products via CO_2 capture and conversion, and water and heat recovery for on-site steam generation.

Regarding the former strategy, various processing pathways leading to CO_2 capture and conversion for producing products, including methanol, acetic acid and synthetic fuel, are proposed within a superstructure network representation. Then each processing pathway is evaluated in terms of economics and CO_2 emissions. Regarding the latter strategy, its key motivations and ideas are introduced, and available techniques are reviewed. Potential CO_2 reductions and economic advantages are also evaluated. Additionally, some challenges expected in designing an optimal process are pointed out. Through the two strategies, CO_2 reductions from the refinery and related economic benefits can be achieved without significantly interrupting the refinery operation.

INTRODUCTION

Due to mounting concerns about climate change and global warming, significant R&D efforts are now being devoted to reducing greenhouse gas (GHG) emissions. According to IEA/UNIDO (2011)[1], among the various stationary sources of carbon dioxide (CO_2) in the industrial sector, refineries represent the third largest GHG emitter, accounting for 10% of the total GHG emissions in the sector, Fig. 1. Typically, a large number of direct and indirect CO_2 emission points are present in a refinery, including the utility plants (electricity and steam production), boilers and furnaces (mainly in the crude distillation units, vacuum distillation units and continuous catalytic reformers), hydrogen plants (employing steam methane reforming or coal gasification) and fluidized catalytic crackers[2, 3].

To reduce the CO_2 emissions of refineries, different strategies have been proposed: energy efficiency improvements; flow rate balancing; feedstock substitution; fuel substitution; hydrogen gas (H_2) management; use of the best available technology and new generation catalysts; and CO_2 capture, utilization (including conversion) and sequestration[3-5]. Table 1 provides a brief description of each strategy.

Several factors affected the selection of CO_2 reduction strategies befitting the refinery in this study, Refinery A. First, the current refinery operation was not to be disturbed in any significant way by them. Second, the refinery, thanks to its location, enjoys a constant supply of crude oil with consistent properties. Third, the refinery operates at constant, fixed production rates. Last, technically mature strategies were preferable. Due to these factors, the focus in this article is on the following two strategies: production of valuable products via CO_2 capture and conversion technologies, and energy efficiency improvements via water and heat water recovery. To discuss these two strategies required that CO_2 emission sources in Refinery A first be analyzed through process simulation. Regarding the carbon capture and conversion strategy, three key conditions were identified that should be satisfied to achieve CO_2 reduction with economic benefits. A superstructure network consisting of various technical alternatives of carbon capture and conversion was created, and promising processing pathways were highlighted and evaluated. Regarding water and heat recovery, its key motivations and ideas were identified, and the potential for CO_2 reduction and expected challenges in design of an optimal process were discussed.

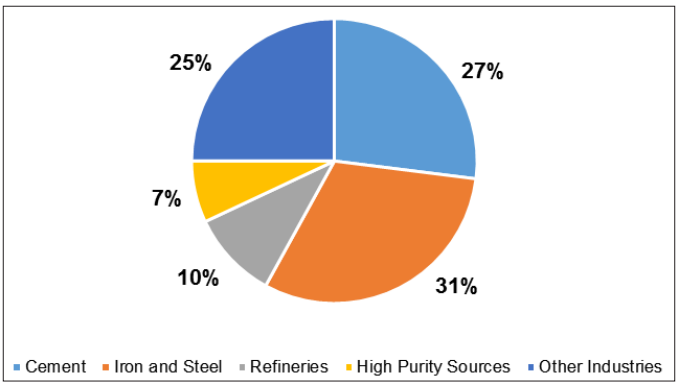

Fig. 1. Industrial CO_2 emission projections in the ETP baseline scenario[1].

Strategy	Description
Energy efficiency improvement	Improve process efficiencies to reduce energy consumption by such as heat recovery integration or utility optimization
Flow rate balancing	Adjust production throughput across the refinery units to reduce CO_2 emissions
Feed substitution	Switch from heavy crude to light crude
Fuel substitution	Switch from heavy hydrocarbon fuel to light hydrocarbon fuel
H_2 management	Recover H_2 from H_2-rich refinery off-gas streams
Use of best available technology and new generation catalyst	Introduce advanced catalysts that lead to higher throughput or lower reaction temperature
Carbon capture, utilization and sequestration	Obtain the concentrated CO_2 streams through separation and sent them to storage or use them, to avoid their emission into the atmosphere

Table 1. Description of various CO_2 reduction strategies for petroleum refineries

ANALYSIS OF CO_2 EMISSION POINTS IN THE TARGET REFINERY

The first step in building an effective CO_2 management strategy for a refinery is to analyze the major CO_2 emission sources in the refinery. Here, modeling and simulation of the emission sources can be quite useful in estimating the amounts of CO_2 emitted from the individual emission sources and to come up with ways to improve the energy efficiency on a short-term basis, as well as to examine the potential of various CO_2 capture and conversion technologies for CO_2 reductions and economic benefits.

In Refinery A, furnace stacks — 35 to 40 — are the primary CO_2 emission point sources; there the refinery fuel supplied from the fuel gas system is combusted to heat various process streams. Each furnace model was developed using the commercial process simulator Aspen HYSYS®, Fig. 2, and the CO_2 emission flow rate in the flue gas stream of each furnace was calculated. This constitutes direct emissions. The amount of the total CO_2 emissions in Refinery A was calculated by summing the direct emissions obtained from the simulation and adding them to the indirect emissions that come from the purchase of electricity.

Figure 3 represents the CO_2 emission distribution in Refinery A. Among the direct emission sources, the crude distillation units are the largest CO_2 emitters, contributing around 21% of the total CO_2 emissions. Refinery A has three different distillation units, all of which need significant amounts of heat

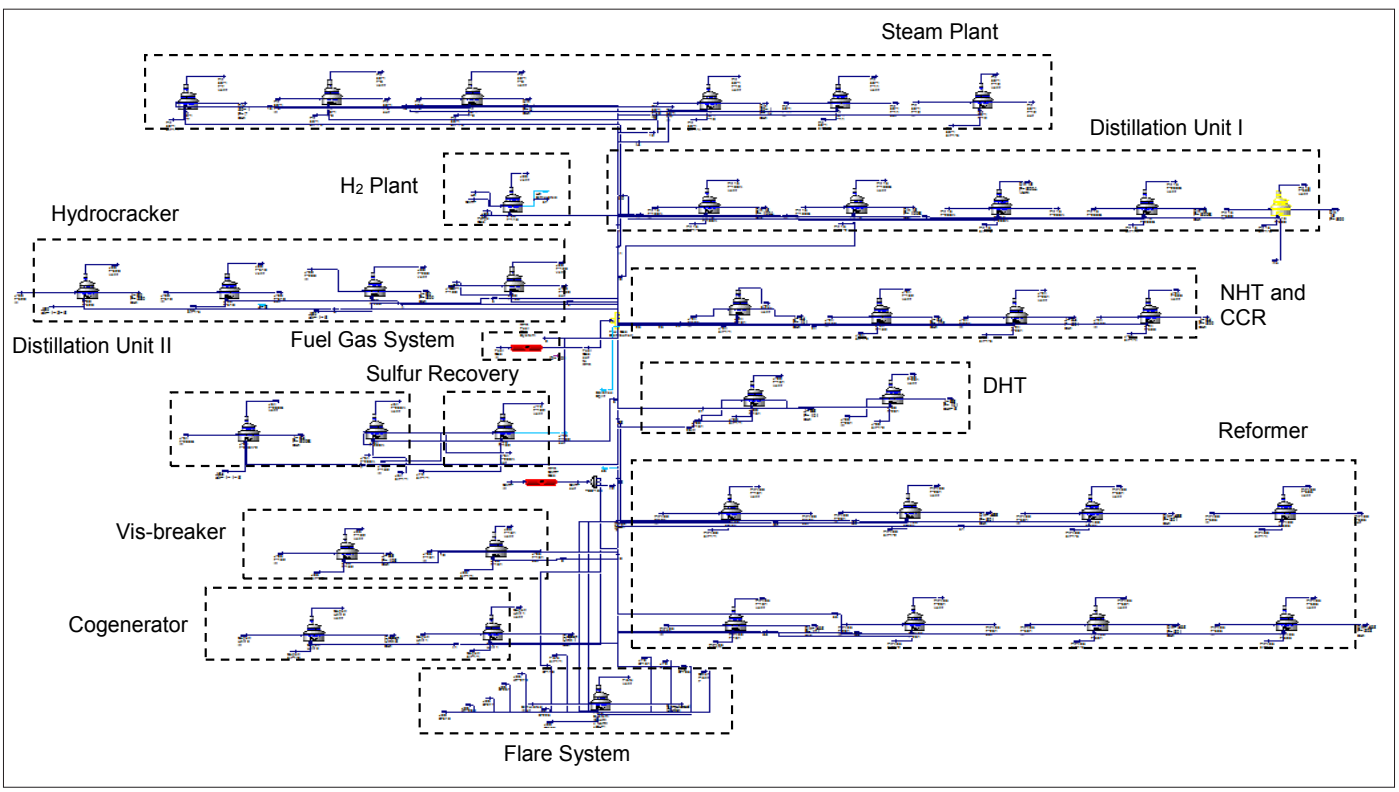

Fig. 2. Refinery A fuel gas system and furnace models developed in Aspen HYSYS®.

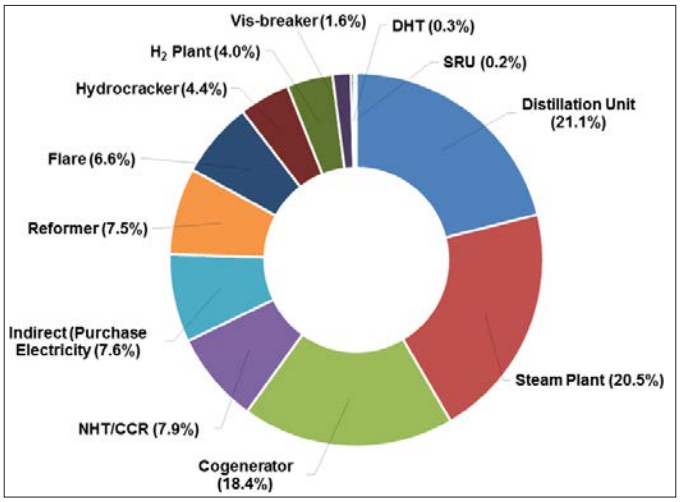

Fig. 3. CO_2 emission distribution in Refinery A.

energy to raise the temperatures of the feed streams. That heat is provided through fuel combustion. The steam plant and the co-generator, which generate heat and electricity, are the next largest emitters as they contribute 20.5% and 18.4% of the total emissions, respectively. Almost 30% of the total fuel gas is consumed within a single process — the steam plant — and therefore this represents a promising target for applying CO_2 management strategies.

The rest of the CO_2 emissions are from other post-processing units such as the naphtha hydrotreater/continuous catalyst regenerator and the reformer, which emit 7.9% and 7.5% of the total CO_2 emissions, respectively. On the other hand, the indirect emissions due to the purchase of electricity account for just 7.6% of the total CO_2 emission in Refinery A.

CO_2 CAPTURE AND CONVERSION

CO_2 capture and conversion is one of the CO_2 reduction strategies that may be particularly applicable to refineries. It is a process that obtains concentrated CO_2 streams through separation and converts them to valuable products via various means, including thermochemical reactions, electrochemical reduction and photo-catalytic reduction. Since there are a number of technical alternatives for capturing and converting CO_2, it is important to select suitable ones for the given CO_2 emission sources.

Several promising CO_2 capture techniques are applicable to Refinery A. Generally, a high CO_2 concentration stream means capture costs will be low. Within Refinery A, the hydrogen plant — employing steam methane reforming (SMR) — is the most immediate target for CO_2 capture due to the high CO_2 concentrations in its flue gas streams. There are two ways to capture CO_2 from the hydrogen plant. One is to capture the CO_2 before separating hydrogen from the syngas mixture, which is produced from the water-gas shift reactor. In this case, both physical absorption, e.g., Selexol™, and chemical absorption, via activated methyl diethanolamine, may be applicable due to the high concentration and partial pressure of CO_2 at this reactor stage. The other is to capture the CO_2 from the reformer furnace's flue gas. In this case, chemical absorption, i.e., using monoethanolamine, or adsorption, i.e., using pressure swing adsorption, can be a good choice. Alternatively, oxyfuel combustion, which utilizes oxygen rather than air for combustion, can be applied. In this case, a complicated capture process is not necessary to obtain the concentrated CO_2 stream. Even so, an air separation unit for obtaining pure oxygen can be costly. For other CO_2 emission sources, including those linked to the utility plant, boilers and furnaces in the refinery, chemical absorption, physical adsorption or oxy-fuel are all applicable.

Regarding CO_2 conversion, various products can be synthesized from captured CO_2. Our group has focused on several products, including synthetic fuel — gasoline and diesel — as well as acetic acid and methanol.

First, gasoline, diesel or acetic acid can be produced through dry reforming of methane (DRM) technology. DRM is one of the more promising CO_2 conversion reactions because one of its feedstocks, natural gas, is cheap and because the high CO_2 feed ratio (CH_4:CO_2 = 1:1) can lead to a large CO_2 reduction effect[6]. The syngas produced from DRM can then yield liquid chemical products via the Fischer Tropsch (FT) process[7], which can be used to produce acetic acid with few byproducts according to its reaction stoichiometry ($2H_2 + 2CO \rightarrow CH_3COOH$).

Second, methanol can be produced from combined reforming and CO_2 hydrogenation. Combined reforming employs two reforming reactions — steam and dry reforming — while CO_2 hydrogenation is a direct methanol synthesis route along with a hydrogen feed. Methanol can be an attractive product to target when considering CO_2 conversion. First, conversion technologies for methanol are relatively mature. Second, global methanol demand is very large (around 100 million metric tons per year in 2013), and its future demand is expected to increase significantly. Finally, methanol is a versatile chemical as it can be utilized as an alternative fuel or as a C1 chemical building block.

CO_2 CAPTURE CONVERSION SUPERSTRUCTURE NETWORK REPRESENTATION FOR REFINERY A

Our group identified some of the major CO_2 emission sources in Refinery A. Depending on the CO_2 concentration in their process streams, the major emission units were categorized into two groups: medium purity CO_2 sources with higher than 15 vol%, e.g., flows upstream and downstream of a hydrogen purification unit at a SMR-based hydrogen plant, and low purity CO_2 sources with lower than 15 vol%, e.g., flue gas from furnaces and utility plants. Additionally, a CO_2 capture-and-conversion superstructure network for the CO_2 emission sources in Refinery A was constructed, which gives a flowchart of the applicable processing pathways, Fig. 4. It includes four stages: CO_2 emission, CO_2 feed preparation (including CO_2 capture

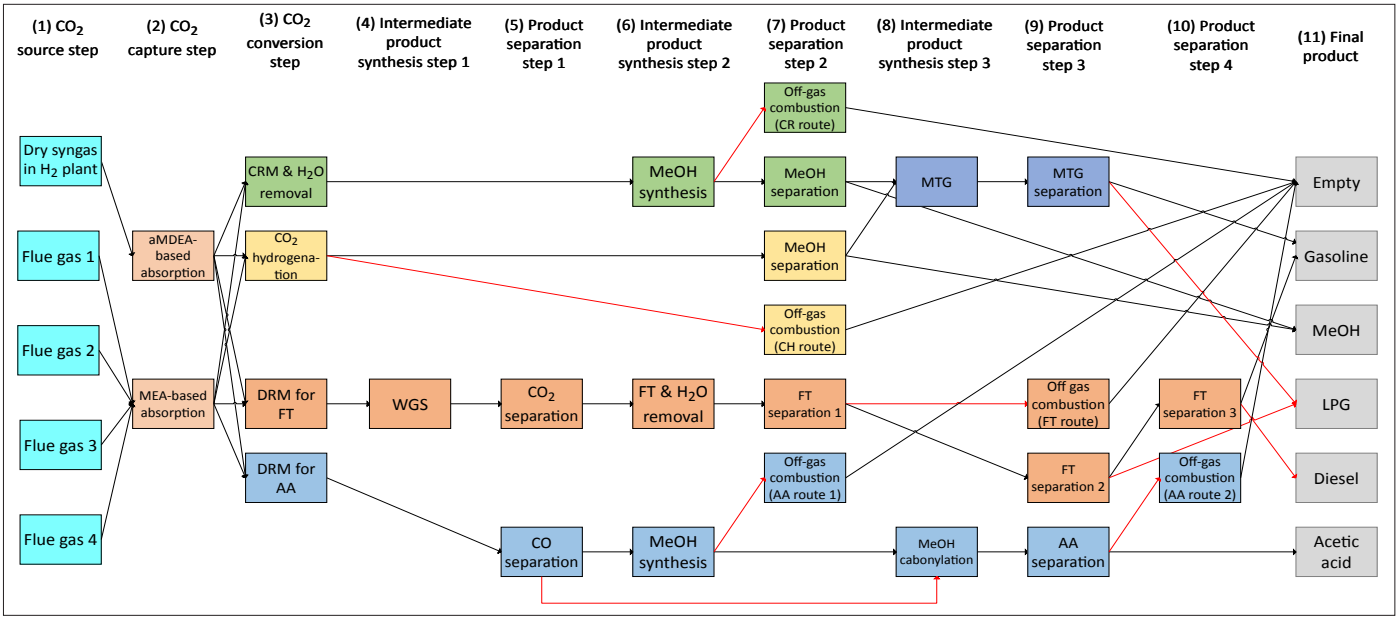

Fig. 4. Superstructure network of CO_2 capture and conversion for a refinery.

techniques), CO_2 conversion and the final product. Each block is connected to multiple candidate options in successive stages. The superstructure makes it possible to identify one or more optimal paths for CO_2 capture and conversion.

The first target was the hydrogen plant, which was connected with chemical absorption technology. Since the dry syngas stream in the hydrogen plant has high CO_2 concentrations at partial pressure, the capture cost of CO_2 here is relatively low. More CO_2 can be captured from other CO_2 emission points if the production rate needs to be increased.

Analysis of CO_2 Capture and Conversion Processes

There are several significant issues in selecting appropriate CO_2 conversion technologies. The first is the market demand for the target products, which should be sufficiently large to consume significant amounts of CO_2, enough to contribute meaningfully to solving the global warming problem. Also, sales income should compensate for the production cost. The second is system boundary identification. The system boundary for CO_2 conversion includes the CO_2 emission source and the processes of CO_2 capture, CO_2 compression, CO_2 transport, CO_2 conversion, product transport and product consumption. Additionally, indirect emissions such as those related to raw material acquisition, manufacture and transport, as well as utility plants — power or steam generation — should be included within the boundary to obtain a meaningful result. Third, a net CO_2 emission comparison — mass of CO_2 per mass of product — is needed. If the net CO_2 emission, which is the sum of direct and indirect CO_2 emissions minus CO_2 consumption, of a processing pathway is negative, this pathway can contribute to reducing CO_2. In the case of a positive value, comparison with a reference case for an equivalent product may be needed to see if existing products should be replaced with the CO_2 driven product[8]. Our group has evaluated net CO_2 emissions and operating costs for several pathways for producing methanol, synthetic

Feed	Cost ($/kg)	Indirect CO_2 Emission (kg of CO_2 eq/kg of Feed)	Notes
Natural gas	2.795	0.359	CME Group, access in January 17, 2015, CME Group (2015)[9]
CO_2 (captured at H_2 plant)	24.06	—	Simulation results
H_2 - SMR	0.74	12.2	Yumurtaci and Belgin (2004)[10], Utgikar and Thiesen (2006)[11]
H_2 - Hydropower	1.28	2.1	
CO	0.6	0.838	Zauba (2016)[12], Althaus et al. (2007)[13]
Utility	**Cost ($/kWh)**	**Indirect CO_2 Emission (kg of CO_2 eq/kWh)**	**Notes**
Power generation	0.951	0.49	Conventional gas fired power plant, Schlömer et al. (2014)[14]

Table 2. Economic and CO_2 emission-related parameters

Product	Poduction Pathway	Operating Cost ($/ton of Product)
Methanol	CO_2 hydrogenation – SMR	216.68
	CO_2 hydrogenation – Hydropower	334.74
	Combined reforming of methane	97.91
	Reference case	91.63
Acetic acid	DRM-Acetic acid	345.63
	Reference case	391.94

Table 3. Operating costs of methanol and acetic acid productions through CO_2 converison and through conventional manufacturing (reference case)

fuel — gasoline and diesel — and acetic acid. The economic and CO_2 life cycle parameters are tabulated in Table 2[9-14]. The results of our evaluation of the economics and CO_2 emissions involved in such production are given in Table 3 and Figs. 5 to 7, respectively.

For methanol production, three pathways were chosen: CO_2 hydrogenation with hydrogen production via hydropower (water splitting), CO_2 hydrogenation with hydrogen production via steam methane reforming, and combined reforming. CO_2 hydrogenation with hydropower-based hydrogen feed shows the best performance in terms of net CO_2 emission. Its operating cost, however, is much higher than others because the hydrogen production with hydropower is very costly. Although the combined reforming pathway has slightly higher operating costs than the reference case, it emits less CO_2. This result illustrates that CO_2 reduction and economics are in a trade-off relationship.

For acetic acid production, the DRM-based pathway shows a lower net CO_2 emission than the conventional synthesis process[13]. Even though the DRM-based pathway emits more CO_2 both directly and indirectly, this is compensated for by the CO_2 consumption in the DRM reaction, so that it ultimately ends up with a lower net CO_2 emission. Therefore, acetic acid production using CO_2 is a feasible option to replace conventional manufacturing of acetic acid.

For synthetic fuel production, the DRM-based pathway is compared with two petroleum refineries treating different crude oils for gasoline production[15]. Since they are producing liquid fuel, net CO_2 emission per energy content is adopted as a comparison criterion. It is difficult to calculate operating costs for gasoline production in a petroleum refinery independently, so only the net CO_2 emission is compared. In comparison with a petroleum refinery that utilizes U.S. offshore crude oil, the DRM pathway does not appear to be competitive. Subsequently, in another case of comparison, this time with Iraqi Light crude oil, a promising result is obtained since the DRM pathway emits less CO_2 (28.7 vs. 43.5). The main reason is that the indirect CO_2 emissions produced in the acquisition and transport of Iraqi crude oil are very significant. From this eval-

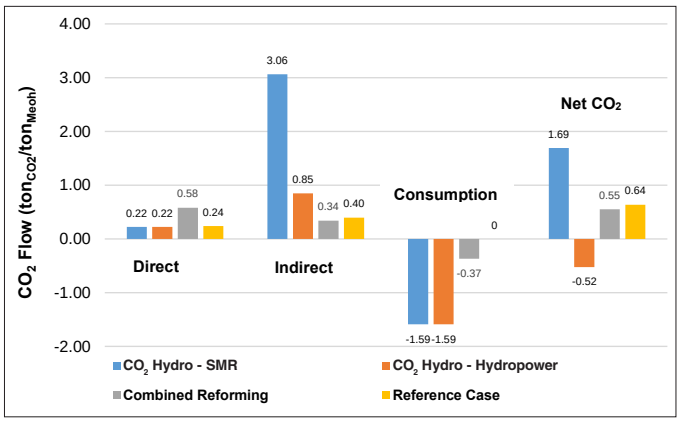

Fig. 5. CO_2 flow for methanol productions via three different processing pathways and via conventional manufacturing (reference case).

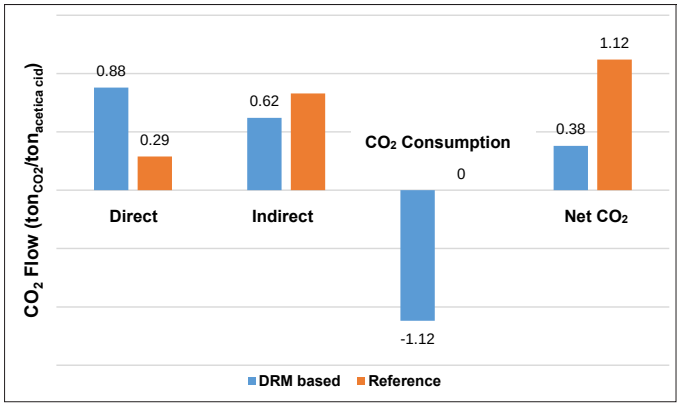

Fig. 6. CO_2 emissions from acetic acid productions via DRM and via conventional manufacturing (reference).

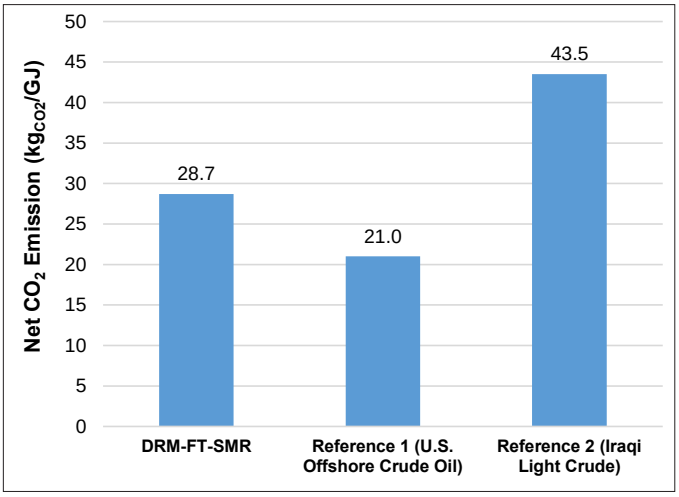

Fig. 7. Net CO_2 emission for fuel productions via DRM and via conventional crude refinings.

uation, it was found that the CO_2 reduction feasibility of the DRM processes for liquid fuel production depends on what conventional manufacturing it is compared against.

WATER AND HEAT RECOVERY SYSTEM

In Refinery A, fuel gas is consumed at crude distillation units, platforming, steam generation, and so on. To apply fuel saving strategies to the reduction of CO_2 emissions in the refinery, the heat producing units with the emission streams were analyzed by modeling and simulation. From the simulation, it was found that 37 flue gas streams can be utilized to recover considerable amounts of energy in the form of heat. Technically, the potential is there to recover water from the flue gas streams as well. In the flue gases, water is present in around 10 vol% ~ 15 vol% at a temperature of 150 °F ~ 250 °F. This is due to the high content of hydrogen — up to 30 vol% — and some light hydrocarbons, including methane and ethane, in the fuel gas used at the furnaces. One can potentially recover both water and heat in the flue gases and send them back to other plants, like the boilers and the steam plant. Based on the available data, a combined water recovery and steam generation plant was proposed to recycle water and thermal energy now being vented to the atmosphere, while generating steam on-site for Refinery A.

Water Recovery System

The main objective of the water recovery system is to decrease the amount of water feed required by the steam plant by recovering water contained in the flue gases. There are three benefits of this application: saving electric energy, reducing the costs in water purification, e.g., desalination, and reducing the costs of water feed transport. Three water recovery techniques are presented next with their pros and cons, and their schematic illustrations are provided in Figs. 8, 9[16] and 10[17].

1. Cooling with condensation: When flue gas is brought below the water dew point, water will condense. The water recovery rate using this technique ranges around 10% ~ 80%. Large-scale applications exist since it is a mature technology. Flue gas streams can be used for improving the thermal efficiency of the process via heat exchange; however, the presence of impurities like sulfur in flue gas requires the installation of post-processing units for purification. Also, anti-corrosion tubing material is needed for the heat exchanger, which is expensive[18, 19].

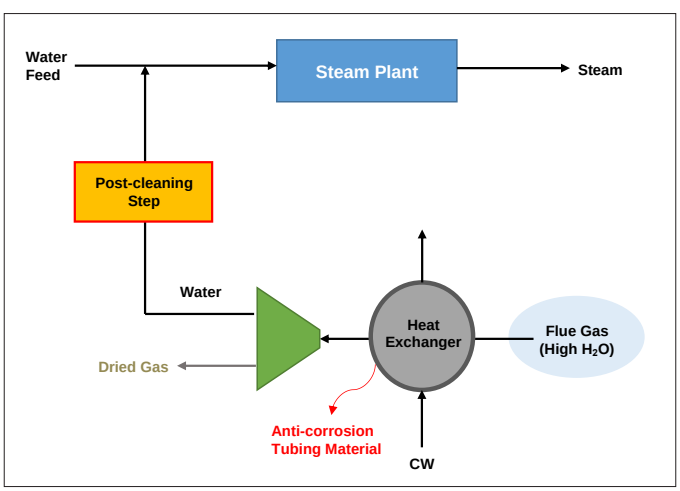

Fig. 8. Schematic diagram of the water condensation process.

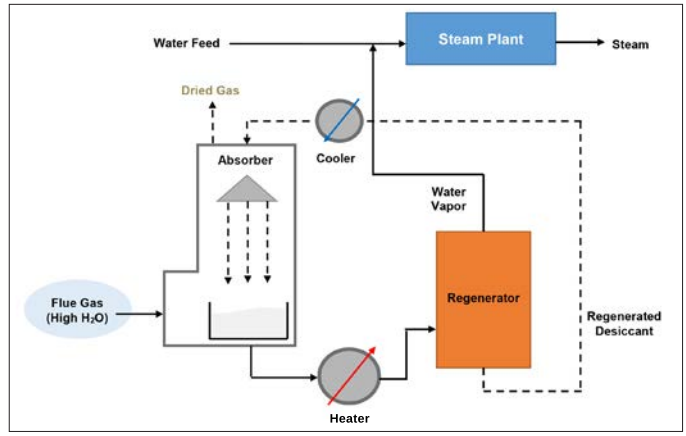

Fig. 9. Schematic diagram of the liquid sorption-based water recovery process. Adapted from Folkedahl et al. (2006)[16].

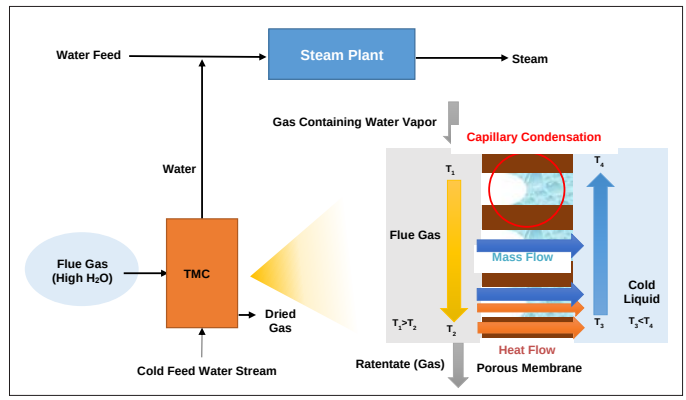

Fig. 10. Schematic diagram of the membrane condenser process. Adapted from Wang et al. (2015)[17].

2. Liquid sorption: This is a desiccant-based processing technique. For the liquid desiccants, aqueous solutions of two basic classes are used: inorganic salts (LiCl, LiBr or CaCl) and glycols (MEG, DEG, TEG or TREG). The water recovery rate of using these techniques ranges around 20% ~ 60%. Large-scale applications exist. This technique guarantees water of high purity, so it is suitable for steam generation; however, the process requires additional heat energy for the regeneration of desiccants. Also, there are safety and environmental risks related to the use of desiccants[16, 18].
3. Membrane condenser: This is also called a transport membrane condenser. This technique is based on a nanoporous ceramic membrane, capillary condensation, and separation mechanism. The technology is in a development phase — no commercial case exists, although it could be the most advanced technology. The water recovery rate of using this

Δ T (°C)	100	200	300	400	500
Fuel saving (%)	2.3	4.5	6.5	8.3	9.9
CO_2 reduction (%)	1.4	2.7	3.9	5.0	5.9
Cost saving ($MM/year)	0.45	0.88	1.27	1.62	1.94

Table 4. Theoretical potential of heat recovery using the hot waste gas stream. Temperature of the waste gas is assumed to be 675 °C

Δ T (°C)	150
Fuel saving (%)	80.7
Water saving (%)	22.0
CO_2 reduction (%)	57.4
Cost saving (MMUSD/year)	21.4

Table 5. Theoretical potential of water and heat recovery using all the flue gases in Refinery A. The flue gases are assumed to be cooled from 180 °C to 30 °C, and 80% of the water vapor is assumed to be captured from the flue gases. Cost saving is the sum of fuel cost saving and water feed cost saving.

technique ranges around 40% ~ 60%. Recovered water is of high quality and mineral free, so it is suitable for steam generation. Also, heat and water recovery can be achieved simultaneously[17].

For Refinery A, the first technique, cooling with condensation, seems to be the most suitable option because the flue gases do not contain any sulfur so that no post-treatment after condensation is required. Also, heat integration using hot flue gases can be applied via heat exchange with cold process streams in the refinery, which reduces the fuel consumption and CO_2 emissions. Finally, since it is a mature technique, it can easily be applied to the actual refinery.

Heat Recovery System

In Refinery A, there are two opportunities for heat recovery. First is a waste gas flow with a very high temperature — over 600 °C — near the crude distillation column, where substantial energy can be recovered for heating process streams. This recovery improves the refinery carbon footprint through fuel savings. Second, flue gas waste heat recovery can be done in the convection section of the existing boiler(s), in addition to the water recovery, to produce low-pressure steam if required.

Tables 4 and 5 summarize the potential fuel saving, cost saving, and CO_2 reduction — based on delta temperature, or the heat transfer between hot and cold streams — for the hot vent gas and the flue gases, respectively. The low heating value of the fuel gas is assumed to be 887 BTU per cubic foot, and the thermal efficiency of fuel combustion is assumed to be 60%. Fuel and water costs are estimated to be $2.85 MMBTU (the price of natural gas in Chicago[20]) and $2/m^3, respectively. According to the calculation results, the water and heat recovery has significant potential in terms of both fuel and cost savings as well as CO_2 reduction in Refinery A.

Challenges in Design of an Optimal Process for Water and Heat Recovery

In designing an optimal water and heat recovery process in the refinery, some challenges need to be overcome. First, there are many flue gas streams in Refinery A — more than 30 stacks in total — and they all have different conditions of composition, flow rate, etc. These different conditions significantly complicate the design of an optimal water and heat recovery system. The presence of many stream candidates comprising the heat exchange networks is another challenge. Therefore, an optimization problem should be formulated using mixed integer (non) linear programming and solved to come up with an overall optimal design for the water and heat recovery process. A superstructure-based approach would be a promising way to tackle the challenges arising in this type of design problem since it can manage a large number of technical alternatives very effectively.

CONCLUSIONS

CO_2 management in the refinery business is going to be an important issue given that petroleum refineries are one of the major CO_2 emission sources in the industrial sector. For the reduction of CO_2 emissions in refineries, various strategies have been proposed, but identifying the proper strategies for a particular refinery is very important as each refinery is in a different situation in terms of location, process configuration, types of feedstock and products, and so on. In this article, two different strategies for reducing CO_2 emissions in a petroleum refinery located in the Middle East are discussed: production of valuable products via CO_2 capture and conversion, and heat and water recovery from refinery flue gases.

Identifying the two strategies required successive steps. First of all, the direct CO_2 emission points associated with the operation of the targeted refinery were analyzed through process simulation. From the analysis, crude distillation units and steam plants were identified as the major emission sources in terms of CO_2 flow rate. Regarding CO_2 capture and conversion, several products that can be produced from the CO_2 sources of Refinery A were analyzed, and it was found that the potential existed to reduce CO_2 emissions and boost profitability. Regarding water and heat recovery, an opportunity existed to reduce both fuel consumption and cost as well as to reduce CO_2 emissions by using the refinery flue gases and a hot waste gas stream. Nevertheless, some significant challenges were faced in the design of an optimal process, and an optimization-based approach would

be needed to come up with an optimal process design that maximizes profit while respecting a CO_2 emission limit.

In conclusion, the two strategies would contribute to building a strategy that achieves both CO_2 reduction and economic benefit. Additionally, the operation of the refinery is unlikely to be interrupted in the course of adopting such a CO_2 reduction strategy, which makes its practical deployment that much easier.

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BIOGRAPHIES

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In 2006, he received the Canadian Council of Ministers for Environment Pollution Prevention Honorable Mention Award for effectively leading the greenhouse gas emissions management program. In 2007, Hasan received the Global Pipeline Award for inventing a "Supersonic Gas-Gas Ejector" technology for rotary equipment leakage applications. The patent was later commercialized by Dresser Rand (USA).

Hasan has three granted patents and four applications in process. He has presented in over 15 international conferences.

Aside from conducting research, Hasan is also the Chairman of the R&DC HSE Audit and Inspection subcommittee, which was recognized our of nine HSE subcommittees in R&DC. He was also recognized as the "2016 R&DC Subcommittee Chair of the Year" for exceptionally leading the subcommittee toward ensuring a safer workplace at R&DC.

Hasan received his M.S. degree in Chemical (Environmental) Engineering from the University of Calgary, Calgary, Alberta, Canada, in 2000.

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Ali also worked in the Ras Tanura Refinery from 2012 to 2013, where he led an engineering team to study and implement an innovative optimization solution to utilize the flared low BTU gases in a fuel gas system. The study was awarded the Saudi Aramco CEO Excellence Award in 2015 for its flare minimization, environmental consideration and cost savings.

Recently, Ali was assigned to work on three projects: anode material development for direct hydrocarbon electro-oxidation in solid oxide fuel cells, enhancement of carbon dioxide (CO_2) utilization and storage in cement and concrete, and an optimization-based study for CO_2 reduction strategies in the refinery process.

He has submitted three patent disclosure applications, published one paper and presented two posters and oral presentations in international conferences.

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Jay previously held visiting appointments at E.I. DuPont de Nemours, Wilmington, DE, in 1994, and at Seoul National University, Seoul, Korea, in 1997. He was a recipient of the National Science Foundation's Young Investigator Award in 1993.

Jay was elected as an Institute of Electrical and Electronics Engineers (IEEE) Fellow and an International Federation of Automatic Control (IFAC) Fellow in 2011, and he became an American Institute of Chemical Engineers (AIChE) Fellow in 2013.

Jay has published over 120 manuscripts in Science Citation Index (SCI) journals, and he has more than 2,500 Institute for Scientific Information (ISI) citations.

Jay's research interests are in the areas of system identification, state estimation, robust control, model predictive control and approximate dynamic programming.

He received his B.S. degree in Chemical Engineering from the University of Washington, Seattle, WA, in 1986, and his Ph.D. degree in Chemical Engineering from the California Institute of Technology, Pasadena, CA, in 1991.

Innovative Diversion Technology Ensures Uniform Stimulation Treatments and Enhances Gas Production: Example from Carbonate and Sandstone Reservoirs

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ABSTRACT

Saudi Arabian nonassociated natural gas development programs are continuously expanding to meet local energy demand. The challenges faced in these new development areas, attributed to reservoir heterogeneity, high-pressure and high temperature, and low reservoir quality, have been thoroughly evaluated and addressed with the application of novel fit-for-purpose technologies and the implementation of best practices. Drilling of horizontal wells and the use of multistage fracturing (MSF) have been preferred practices to obtain and maintain high and sustainable production. Stimulation also helps marginal wells become economical. One main focus area for the enhancement and improvement of stimulation efficiency is fracturing fluid additives. Regardless of the base gel and loading used, the additives play a major role in acid etching or proppant transport in heterogeneous reservoirs. Additives are needed to attain uniform stimulation, maintain high fracture conductivity and accelerate post-fracture cleanup.

Because of reservoir heterogeneity, the varying extent of permeability and the multiple net pay sections that need to be stimulated in a horizontal well, ensuring uniform fracture propagation, acid penetration and proppant placement is challenging. Effective completion and stimulation design is necessary. The location of perforations is important and can impact fracture growth. The diversion additives in the fracturing fluid ensure that perforation clusters are all treated sequentially. They assist and enhance acid interaction or proppant distribution inside the fracture, and they increase the effective fracture geometry, contact area and overall conductivity. This article highlights the importance of perforation placement and discusses in detail a novel diversion technology, including a control pressure pumping (CPP) mechanism for additive deployment. This technology has been successfully applied in several high-pressure and high temperature tight gas condensate reservoirs to optimize breakdown, acid penetration and proppant transport. The result has been to maximize stimulated volume and well productivity.

Several wells that have been acid fractured, matrix acidized or proppant fractured using these novel diversion materials are discussed in this article. Various diagnostics used to verify stimulation coverage in these wells include running production and temperature logs, conducting distributed acoustic and temperature measurements, and pumping nonradioactive tracers. Although these wells exhibited a wide range of porosity and permeability variation along the drilled section, each perforated interval was effectively stimulated using the novel diversion materials. Compared to offset wells where diversion was not used, wells treated with the novel diversion showed a distinct difference in acid etching or proppant placement profiles, indicating greater stimulation. The total production rate observed was much higher in the wells where the novel diversions were applied.

INTRODUCTION

Use of fracturing fluids that have been optimized for a given reservoir and well condition is an essential part of successful hydraulic fracturing treatments. Table 1 provides a quick review of some of the important aspects of an "ideal" fracturing fluid system.

Developing tight gas condensate reservoirs requires specific practices. These include drilling in the minimum stress direction, completing wells open hole or with a cemented liner, perforating in clusters spread out across permeable intervals, as identified by open hole logs, and conducting fracture stimulation. This article focuses on the use of novel diversion technology that enables efficient fracture treatment and ensures sequential and uniform acid or proppant distribution along the heterogeneous intervals that are open to the wellbore.

Clusters are perforations that open the well to the formation. The optimal method to complete a well requires specifying the perforation cluster location, the interval length and the total number of clusters that can most efficiently treat the reservoir. To reduce treatment time and cost, the clusters are combined in sections so that a single stimulation treatment can cover a number of clusters (and possibly a long interval) without compromising stimulation efficiency.

The two ways of assessing cluster efficiency are to calculate the cluster stimulation efficiency (CSE) and the cluster production efficiency (CPE). CSE is the percentage of clusters that takes the fracture fluids during pumping operation. A higher efficiency value would mean the generation of a greater number of highly conductive transverse fractures with more uniform

Ideal Characteristics	Benefits
Shear and temperature resistant to degradation	Helps to ensure viscous stability — needed to create and propagate fractures and to transport proppant
Minimum friction loss in tubing and perforation	Minimizes pumping pressure requirements
Controlled leakoff	Ensures deep fracture penetration and minimal formation damage
Compatible with formation and formation fluids	Minimizes clay swelling, scaling, etc.
Low polymer concentration	Enables the retention of high fracture conductivity
Delay mechanism	Helps ensure the retention of fluid properties across high shear regions
Breaking additives	Enable fast and efficient cleanup after treatment
Diversion additives	Help ensure uniform stimulation in all intervals of interest
Acids (for carbonates) — emulsified, retarded, controlled reaction rate	Ensure deep penetration and optimizes wormholes

Table 1. Ideal fracturing fluid characteristics

half-lengths. CPE relates to the percentage of clusters that contributes to gas production. In non-ideal cases, when neither the placement of the clusters nor the pumped fluids are engineered using comprehensive study and modeling, the efficiency is typically low, falling below 50%. In ideal cases, both percentages can be high, exceeding 80%. A typical stimulation treatment and the resulting production from the perforation clusters, Fig. 1, shows only 50% of the clusters were treated and that 70% of the gas is coming out of 20% of the clusters. This is a very inefficient cluster placement and stimulation treatment that needs to be significantly improved. The effect of stress shadow and high stress created near the well due to a previous fracture can also dominate and prevent the subsequent fracture growth, Fig. 2.

Improvement is possible with diversion methods. The novel diversion materials discussed here are sorted and adjusted via control pressure pumping (CPP). The small induced fractures, as well as natural fractures already present within the reservoir, are blocked with these well sorted, very small-size novel diversion materials. They provide leakoff prevention and allow single fracture propagation. The bigger size novel diversion materials are used to divert the fluids from one cluster to another, thereby separately treating each cluster. The pumping of novel diversion materials is synchronized with the CPP rate so as to shut down small fractures and enhance the effectiveness of the dominant fracture.

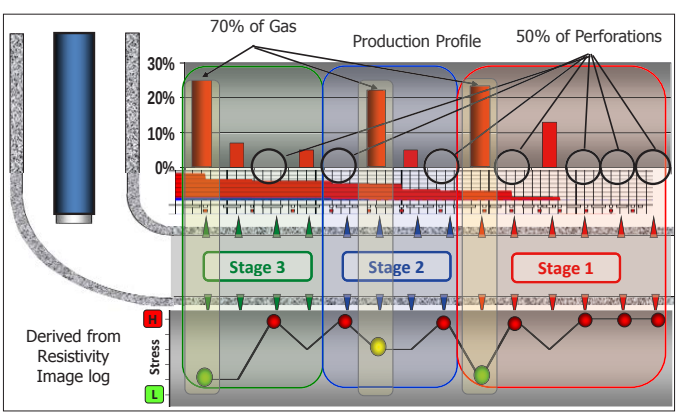

Fig. 1. Geometric well configuration of a well with equidistant clusters after conventional stimulation treatment showing much of the gas reserves remaining behind the pipe.

ACHIEVING OPTIMAL ACID AND PROPPANT DISTRIBUTION

During matrix acid treatments, unless proper measures are undertaken, acid will flow preferentially to the high permeability section, leaving other reservoir intervals unstimulated. This results in a much lower post-stimulation productivity compared to what could be achieved if all the intervals were treated. The industry uses several techniques to attain uniform and effective stimulation[1]. There are mechanical isolation methods to force the fluids into the intended section of the formation, such as bridge plugs and packers. Needless to say, such operations are time-consuming and carry associated risks as each perforation interval must be treated separately with numerous in-hole and out-of-hole trips to set and unset the packers. Technology based in the application of ball sealers came to market in 1956, wherein nylon or rubber balls are dropped to block the initial perforations that took the stimulation treatment so subsequent fluid stages can be diverted to the remaining open perforations. Such a diversion is highly inaccurate, however, because hole and perforation conditions may not allow ball setting in the desired perforations; moreover, these balls can easily break during pumping operations.

Another option is to use coiled tubing to selectively treat intervals. This is also not very effective because of pump rate limitations, the chance of quick tube corrosion with the use of high strength acids, associated costs and operational inefficiency.
A fourth method is the protective injection method, which involves the injection of inert fluid into the most prolific reservoir interval to form a barrier, so the stimulation acid subsequently

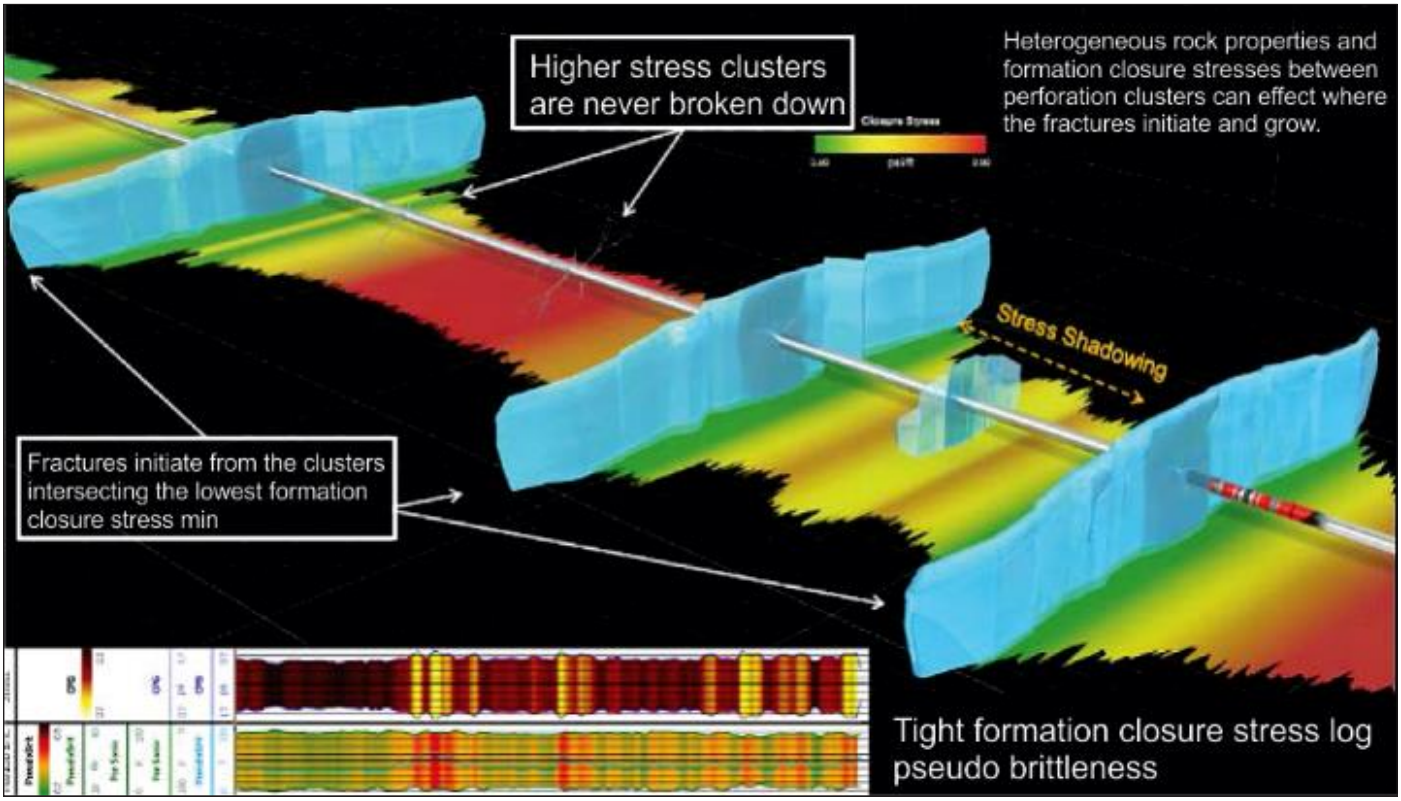

Fig. 2. Effects of high stress and stress shadowing on fracture propagation.

pumped is then naturally diverted to and forced into the other lower quality intervals.

Another option is the use of chemical diverters, such as salt granules, foam, fibers, viscous pills, waxes and resins; all are often used in the industry. One benefit of using foams or gels is that they are not particulates; therefore, cleanup is easier and the formation damage is reduced. The novel diversion materials that are the focus of the current work are mechanical biodegradable diverters. These are particulates derived from natural sources, which are very efficient in creating temporary obstacles to the clusters, Fig. 3. This is shown by the increase in pressure as these materials hit the perforations — or mechanical mesh in laboratory tests, Fig. 4 — during pumping. At the end of the treatment, these particulates degrade completely, leaving zero residue inside the fracture, Fig. 5. The pumping sequence is designed meticulously so that the novel diversion materials are pumped at the exact moment they are needed to block the created fractures and to build up pressure to initiate a new fracture.

WELL COMPLETIONS FOR MSF TREATMENTS

The two types of completions implemented in horizontal wells are (1) open hole with a multistage fracturing (MSF) port and packer assembly, and (2) cased hole with a cemented liner and the plug-and-perf stimulation system. In open hole systems, packers are the means to isolate stages, and fractures initiate anywhere within the open hole interval depending on in situ stress conditions. The challenge faced in such completions is how to maintain proper isolation and also how to ensure one dominant fracture growth instead of multiple fractures, which

Fig. 3. Biodegradable diverter materials.

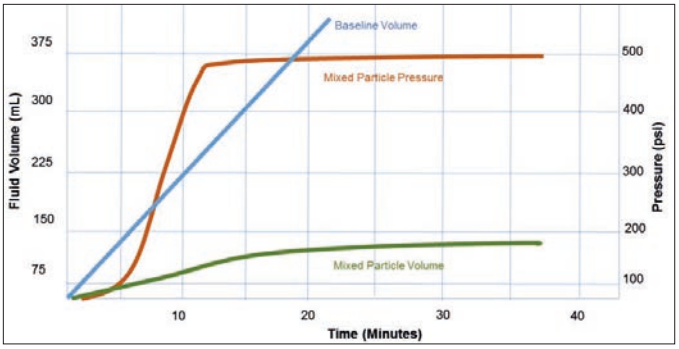

Fig. 4. Pressure buildup attributed to the application of novel diversion materials (laboratory measurements).

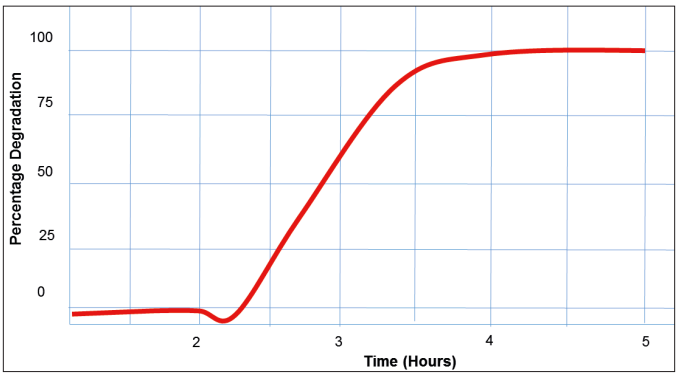

Fig. 5. Rapid and complete degradation of novel diversion materials, after giving enough time to complete the treatment at 310 °F (on-site quality control).

can easily initiate because of the long open hole interval and reservoir heterogeneity.

In the cased hole system, the entry points can be a conventional single set of perforations per interval or multiple cluster perforations within the same zone. In tight formations, clusters are preferred because multiple entry and stimulation points usually provide a greater chance to target and stimulate several sweet intervals simultaneously. To be successful, cluster placement is engineered and the stimulation treatment is optimized. That is because cluster perforations face challenges when they are treated by a single pumping operation. If neither the cluster perforation placement nor the stimulation parameters are designed properly, stress interference can result in lower CSE and CPE. A phenomenon known as stress shadowing, demonstrated by Cheng (2012)[3] and Shin and Sharma (2014)[4], is when a higher stress is generated by induced fractures, thereby significantly reducing fracture width and conductivity.

Simultaneous fracture initiations at multiple clusters can also act as competing fractures, and some of them can dilate more by receiving extra stimulation fluid. Studies have demonstrated that in a homogeneous stress environment, the inner clusters will have their dilation suppressed by the edge fractures. This increased stress can impede subsequent fracture propagation and reduce fracture dimension. Some clusters that can accept initial fluids might not be able to accept proppant due to this reduced width. In the case of such a stress change scenario, the outer clusters could achieve better growth because of a more normal in situ stress environment, while growth in the inner clusters could be adversely affected by high stress. The stress will increase with the increased number of perforation locations and the reduced distance between two sets of perforations. As the dominant fractures initiate in the lower stress intervals (outer clusters), it becomes very difficult to break down the higher stress clusters. This can happen only if the already fractured zones are somehow blocked and isolated.

DIVERSION TECHNOLOGY

The objective of using a diversion in hydraulic fracturing is twofold: (1) ensuring that each perforation cluster accepts stimulation treatment, and (2) diverting fluids sequentially from the high permeability intervals to low permeability intervals, thereby overcoming reservoir heterogeneity to assure that all zones are treated and that the desired fracture penetration is achieved. Novel diversion materials therefore must have two important characteristics — they must be able to divert fluids near the wellbore in the perforated section and they must be able to ensure deep penetration by preventing small fracture growth. Novel diversion materials are pumped in between stages (intra-stage) — e.g., between two acid sequences. The diverter creates a temporary blockage in zones that preferentially take the fluids because of their high flow capacity, thereby directing the treatments to other not-so-prolific intervals. The concept of an intra-stage deployment requires that the novel diversion materials be environmentally acceptable chemicals that can create an effective blockage, and also be biodegradable, self-removing and residue-free.

The dominant clusters taking fluid initially, as previously indicated in Fig. 1 (Clusters 1, 6 and 9), can be bridged and isolated by pumping diversion materials that block fluid intake and create an elevated bottom-hole treating pressure. This will facilitate the breakdown of subsequent clusters, which will be encountering higher formation stresses, and overcome the stress shadow placed in the interval by the initial dominant fractures, as previously shown in Fig. 2. The multi-treatment approach to a single stage also increases the chance of creating a unique and independent fracture at every perforation cluster, rather than having all fractures grow into one single fracture[2] in a big interval, which can cause bypassing of hydrocarbon reserves.

Depending on reservoir conditions, the novel diversion materials can also include a breaking material, deployed in the near wellbore region as well as within the formation, which will degrade the fluid entirely with time and temperature increases, requiring no special solvents or additional surface operations.

Stage intervals with multiple clusters present two distinct challenges to completion cluster efficiency. A primary challenge is the heterogeneity in geomechanical properties (closure stress, Young's modulus and Poisson's ratio) that can lead to varying fracture initiation pressures, geometry and propagation along the lateral. The lower stress clusters will initially take the majority of the stimulation energy.

The incorporation of an intra-stage diversion on some or

all of the stages of a well is possible in almost every multistage or multi-perforation completion. It can aid in reaching higher completion cluster efficiencies and provide a more complete fracture network with more access points to the wellbore. Field results show improved initial production and longer sustained producing rates, thereby indicating higher recovery factors[2].

CPP

CPP is a process to improve dominant fracture initiation and propagation by delivering a rapid net pressure boost in a fracture. This is accomplished by means of specifically designed rate variation procedures to achieve optimal tensile opening. Depending on operator needs and specific area goals, CPP can be designed for a variety of stimulation fluid viscosities to initiate predominant planar fracture growth or to dilate more complex fractures. This raises the intensity of shear fracturing events, which increases the connection with the reservoir's matrix porosity system and can hydraulically connect various natural fracture systems. The benefits of the CPP technique include, but are not limited to:

- Pressure dependent leakoff control.
- Net pressure optimization.
- Reduced screen out risk.
- Complex fracturing process control.
- Enhanced fracture initiation control for fracture designs using diverter systems.

In the following field examples, CPP was performed in conjunction with near wellbore novel diversion to break down the maximum number of clusters and maintain a constant impulse flow velocity during the cycle. The goal was to produce the most consistent near wellbore intra-stage diversion effects. In general, for multicycle scenarios, CPP assists with creating more predictable — and greater — stress contrast envelopes to manage exit point discharge while fracturing and diverting.

SAUDI ARABIAN FIELD EXAMPLES

Three field examples are provided in this section, describing wells treated with novel diversion technology.

Well-A was the first well where both near wellbore and deep penetration novel diversion was employed, with materials pumped at a high rate, as part of a matrix acidizing treatment.

Well-B was an acid fracturing candidate where deep penetration novel diversion was used, pumped along with near wellbore novel diversion.

Well-C was a horizontal well where a proppant fracturing treatment was conducted in seven stages on an open hole completion and where near wellbore novel diversion was used to treat the stage with the longest open hole interval.

In both Well-A and Well-B, results were assessed using the post-fracture temperature logs, which show the treatment intervals as indicated by cool-down effects. In Well-C, a production match was performed to evaluate the near wellbore novel diversion's effect on the open hole MSF fracturing design.

Well-A: Carbonate Matrix Acidizing

Well-A is a vertical well affected by the depletion that occurred over time in the area. It was decided to stimulate the carbonate formation using a nitrogen energized, high rate matrix acidizing treatment.

This well was challenging with its 90 ft of discontinuous total perforation length spaced out into five different clusters. The entire interval length from the top perforation to the bottom was 150 ft. Without a good diverter technique, it would be difficult to achieve uniform stimulation of all perforation sets because an acid treatment would tend to flow to the points of least resistance — lower stress areas and higher permeability zones.

The complexity was coupled with the fact that the target formation interval exhibited heterogeneity in formation stress and porosity, Fig. 6. That meant that a conventional high rate matrix acidizing treatment would stimulate the "sweet spots," leaving intervals with lower formation quality untreated.

The data for the well was reviewed, and a combination of far-field and near wellbore self-degrading diverters was proposed to address the challenge. This type of diverter combination had never been pumped for a matrix acidizing treatment in the past, but it was found to be very effective in this case.

Porosity and stress profiles were reviewed, and software simulation was performed to evaluate which of the perforated intervals would tend to accept fluid first and so would require isolation with the initial diverter drop. The simulation outcome showed that most of the stimulation fluids would likely invade the two lower perforation sets first, with a total of 40 ft perforated net or 240 perforation holes total (perforation sets #1 and # 2 in Fig. 6). Secondary fluid invasion was located at perforation sets #3 and #4, Fig. 6; therefore, a second diverter drop would account for 35 ft of perforated net or 210 perforation holes. The last perforation cluster (perforation set #5, Fig. 6) — accounting for 15 ft perforated net or 90 perforation holes — had the lowest formation quality and so was planned to be stimulated with the last treatment cycle, after fluid flows to the rest of the clusters had been restricted by the preceding diverter drops.

It was determined that other factors could significantly complicate the treatment. Perforation set #3 faced the dolomite section of the reservoir, while the rest of the intervals were mostly limestone. Rock lithology contributing to formation heterogeneity affects etching. The chemical and physical composition of the formation rock influences the reaction rate, so some areas can have significantly higher dissolution and leakoff rates compared to others[3].

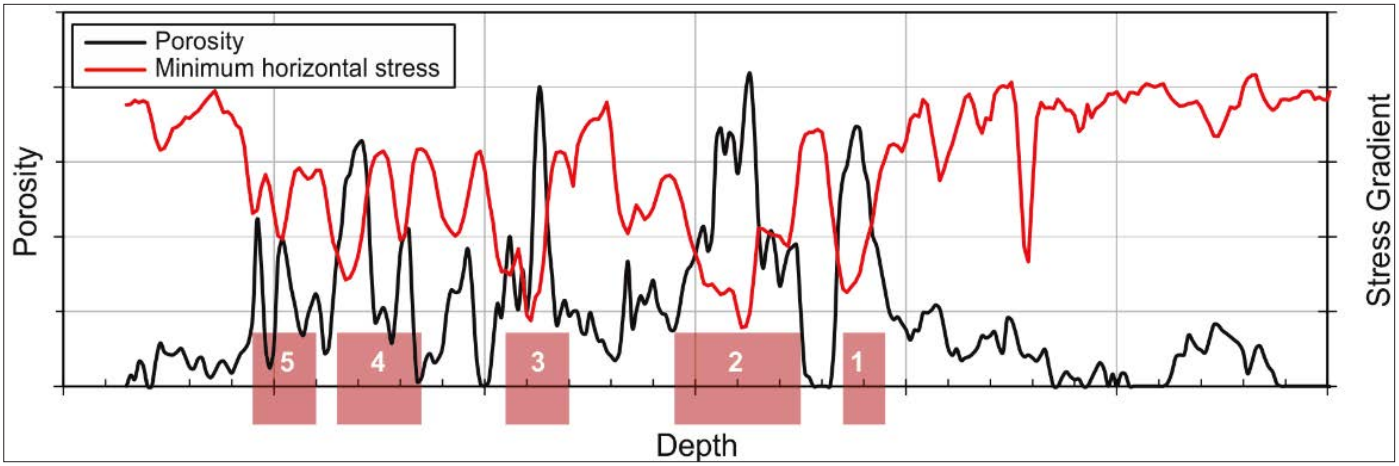

Fig. 6. Porosity and stress profiles across the five perforation intervals or sets for Well-A.

Based on this study, the treatment was designed for three acidizing cycles and two near wellbore diverter intra-stages. The first cycle was intended to stimulate perforation sets #1 and #2, and the flow was to be redirected with the first near wellbore diverter, which would be dropped immediately after that. The second cycle would treat sets #3 and #4, with the flow then diverted by a second near wellbore diverter drop, and the final cycle would stimulate cluster #5, completing the operation.

The treatment volume was designed with approximately 270 gallons of hydrochloric acid per perforated foot (gpf). The design of the diverter intra-stages was reviewed thoroughly, taking into account the possible number of effective perforations open. The total mass and concentration of the diverter per drop and delivery capacity was calculated. A stand-alone blending unit and high-pressure pumps were dedicated to ensure smooth diverter delivery.

The treatment fluid was nitrified to assist faster cleanup. High internal phase fraction was not the goal, since the formation required slight assistance, so the nitrogen rate was kept in a range of 5,000 standard cubic feet per minute (SCFM) to 8,000 SCFM, leading to an average of 30% internal phase fraction. In the flush stage, the fraction was increased up to 60%. During the surface diverter drops, nitrogen was on hold to maintain the highest diverter concentration possible. The average clean rate was approximately 12 bbl/min, and no rate reduction was necessary when the diverter was added to the stimulation fluid or arrived at the perforations. Based on the first response, the second drop was increased as the operation proceeded — such flexibility is one of the main advantages of the system. A total of ~1,400 lbm of near wellbore novel diversion material was used for the operation. The differential pressure increase observed was in the range of 300 psi to 400 psi, but it is quite hard to estimate such increases with a high level of accuracy based on surface pressure readings, Fig. 7.

As an additional aid, a far-field diverter drop was used between the near wellbore intra-stages. Pumped at lower concentrations, these drops were intended to enhance complexity in the wormhole network by penetrating deep into the reservoir and creating a bridging effect at the points where spurt loss occurs. The path of least resistance was constrained, and stimulation fluid was redirected to unstimulated areas.

Due to the organic nature of the product, both near wellbore and far-field novel diversion materials completely degrade with time, leaving no residue. A slightly acidic environment is formed once the novel diversion material degrades, which, in the case of conventional proppant fracturing, can serve as addi-

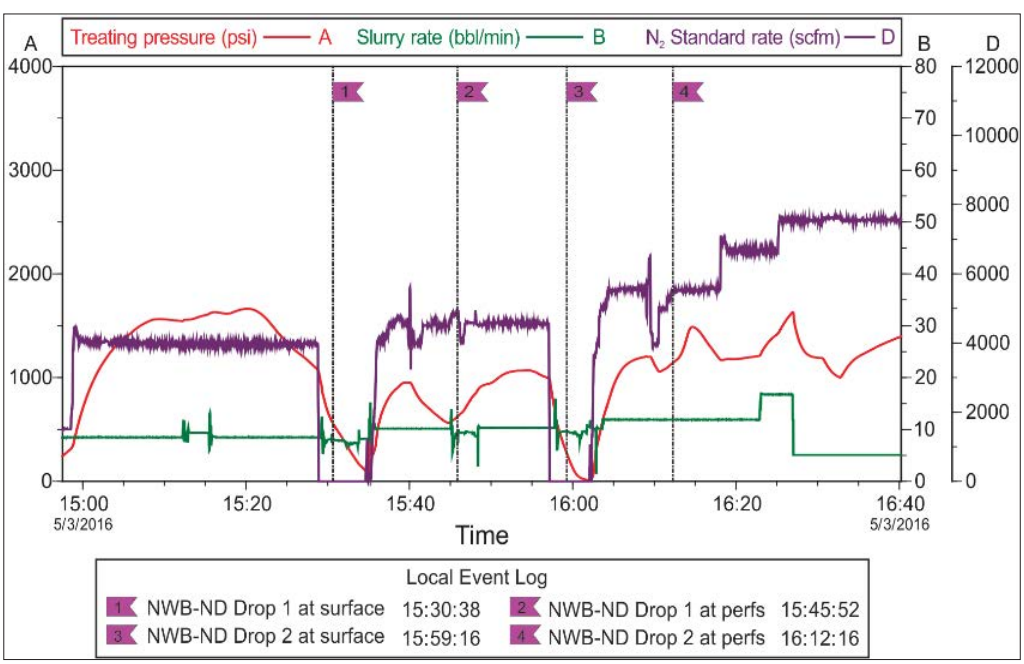

Fig. 7. Fracture treatment plot, Well-A.

tional add-in, breaking the crosslinked gel after the treatment as the bottom-hole temperature returns to static conditions. Laboratory tests were performed before the treatment to ensure the diversion material was able to hold the differential pressure for the pumping time and then completely degrade afterward at the given bottom-hole static temperature, previously seen in Fig. 5. These tests are relatively simple to conduct, both in the laboratory and in the field.

Treatment was successfully performed as per design, and a high resolution temperature log was run soon after the stimulation to evaluate its effect by observing the cool-down distribution deviation from the base line across the interval. The temperature drop as measured was even across the perforated intervals, confirming that the necessary diversion was achieved,

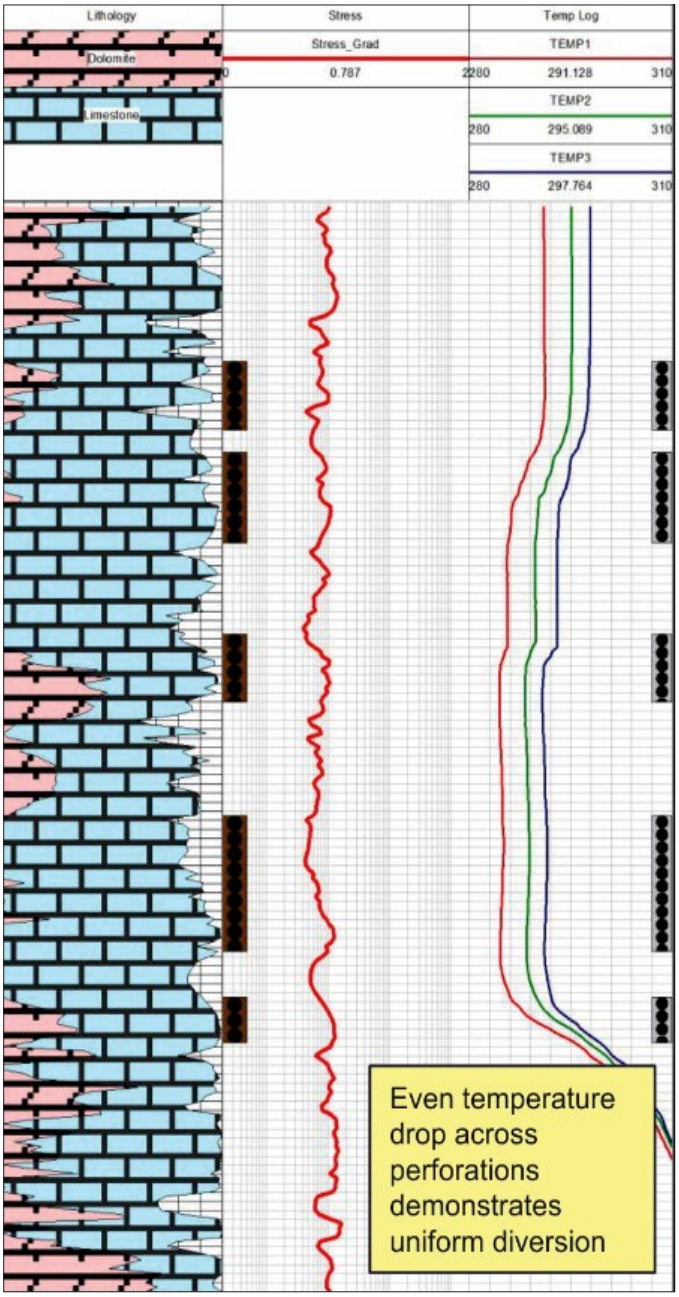

Fig. 8. Lithology, perforation intervals, and temperature log for Well-A used to confirm diversion success.

Fig. 8. A stabilized production rate of 13 million standard cubic ft per day (MMscfd) was achieved at a wellhead pressure (WHP) exceeding the minimum value necessary to put a well on production. A nodal analysis production match was conducted, and a skin of -3.2 was calculated as a result of stimulation, Fig. 9.

Another calculation that is used to evaluate well success is the productivity index (PI), which is production rate divided by pressure drawdown — a difference between the current reservoir pressure and the flowing bottom-hole pressure. If one assumes that well conditions will not deteriorate with time (because of scale precipitation or any other reason that could influence skin effect), the PI should remain constant, even if production rate and formation pressure change throughout the well's life[4]. A PI analysis was performed based on flow back data and showed that the well has significant potential. The PI was twice as high as that of a good offset producer well within the same formation that was stimulated earlier with conventional acidizing at 300 gpf acid loading, Fig. 10. The well is considered a highly successful pilot of matrix acidizing treatment using a combination of near wellbore and deep penetration novel diversion.

Well-B: Carbonate Acid Fracturing

Well-B is a vertical well completion with three separation sets having a total length of 50 ft in a carbonate interval. The objective for this well was to perform a high rate fracture acidizing treatment to cover the entire range of perforations.

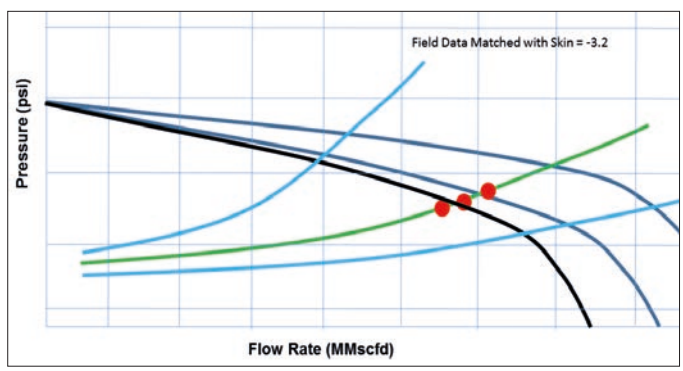

Fig. 9. Production nodal analysis and production match, Well-A.

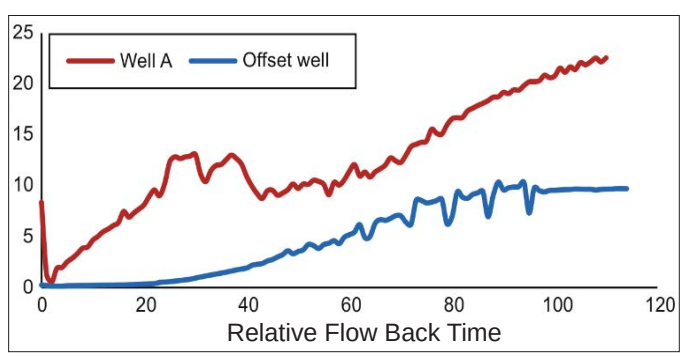

Fig. 10. Comparison of Well-A PI with the PI of a conventionally stimulated offset well.

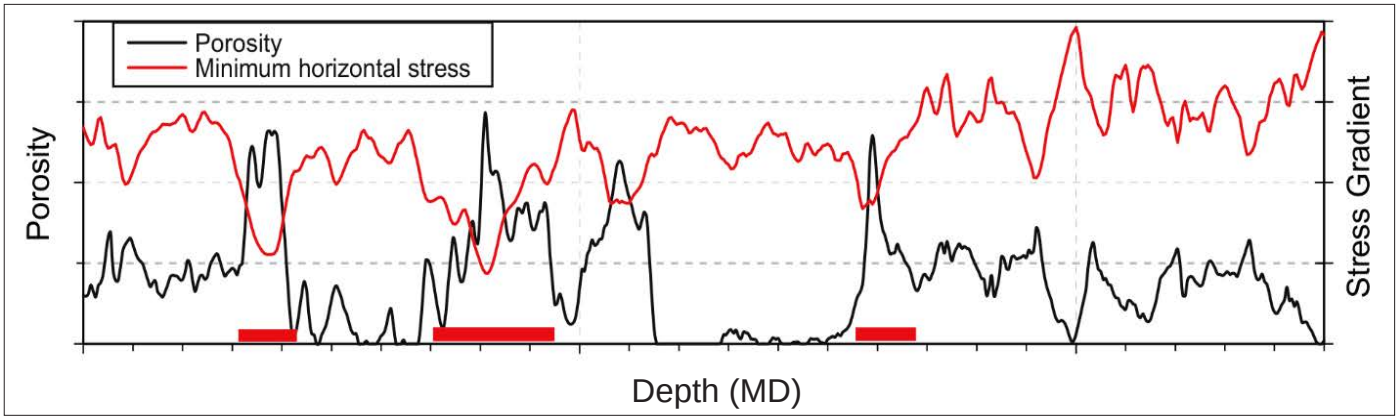

Fig. 11. Porosity and stress profiles across the three perforation intervals or sets (marked in red) for Well-B.

The porosity and in situ stress profiles, Fig. 11, indicated a significant variation of stress values. Two upper perforation sets were facing similar formation stresses, while a third set (on the right side of Fig. 11) was facing a higher stress. The lowest perforation set was placed in front of the dolomitic section of the interval, which usually has higher in situ stress and higher Young's modulus in the area, and so would require higher breakdown pressures to initiate fracture.

Acid fracturing was designed and conducted in three stimulation cycles (including a deep penetration novel diversion), separated by two intra-stages of near wellbore novel diversion, Fig. 12. The pumping rate was reduced during the surface stages of the near wellbore novel diversion to maintain the highest possible concentration. The pumping rate was also lowered at the time that the near wellbore diverter landed at the perforations to observe the diversion effect.

The rate varied from 30 bbl/min to 40 bbl/min, depending on changes in WHP attributed to the friction pressure response of the different stimulation fluids; however, the intention was to maintain the highest rate possible for fracture propagation. Approximately 1,400 lbm of deep penetration novel diversion materials and 2,200 lbm of near wellbore novel diversion materials were used during the treatment. The CPP procedure was performed to reduce pressure dissipation, which typically occurs in naturally fractured formations.

A high resolution temperature log was run after the main treatment, Fig. 13, indicating very effective stimulation in the upper two sections and moderate cool-down effects in the lower section. Multiple factors could have affected the relative smallness of the lower cluster's temperature defection. The lowest perforation set was 62 ft away from the upper two sets. Higher temperature surroundings, a higher diffusion rate, dolomite content and lower reservoir quality have all played a role in temperature trend curvature. Therefore, further production analysis was necessary to estimate each cluster's contribution and evaluate the diversion effectiveness.

From the production logging tool (PLT) run and processed data, Fig. 14, it can be seen that most of the contribution comes from the middle perforation set, while the rest of the intervals show low to intermediate level contributions. Production data was matched using nodal software to obtain the skin value associated with each producing interval, Fig. 15. It can be seen that skin values across all perforated intervals range from -4.5 to -5, which indicates that the intervals were equally treated. Therefore, the production difference depends on the formation quality of each zone. The calculated skin factors were used as input parameters for another software program intended to estimate reservoir quality. The permeability thickness value was calculated for each one of the intervals, Fig. 16. Taking into account skin values achieved as a result of stimulation and the permeability thickness obtained from the history match, each interval production correlated to the rock properties at each given depth. Near wellbore conditions are characterized by skin, which was found to be consistent along all perforated intervals.

Well-B's post-treatment stabilized rate exceeded 6 MMscfd at a high WHP. The stimula-

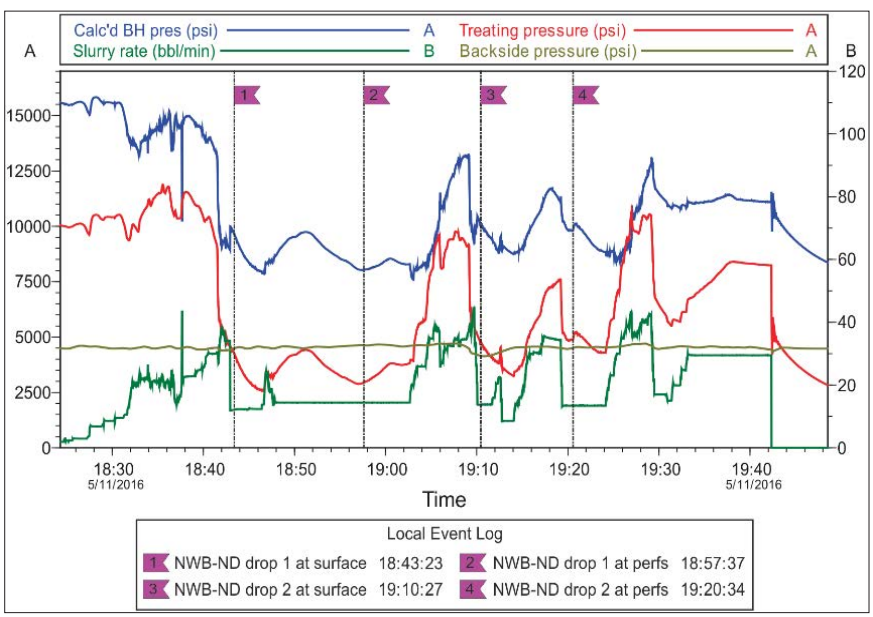

Fig. 12. Fracture treatment plot, Well-B.

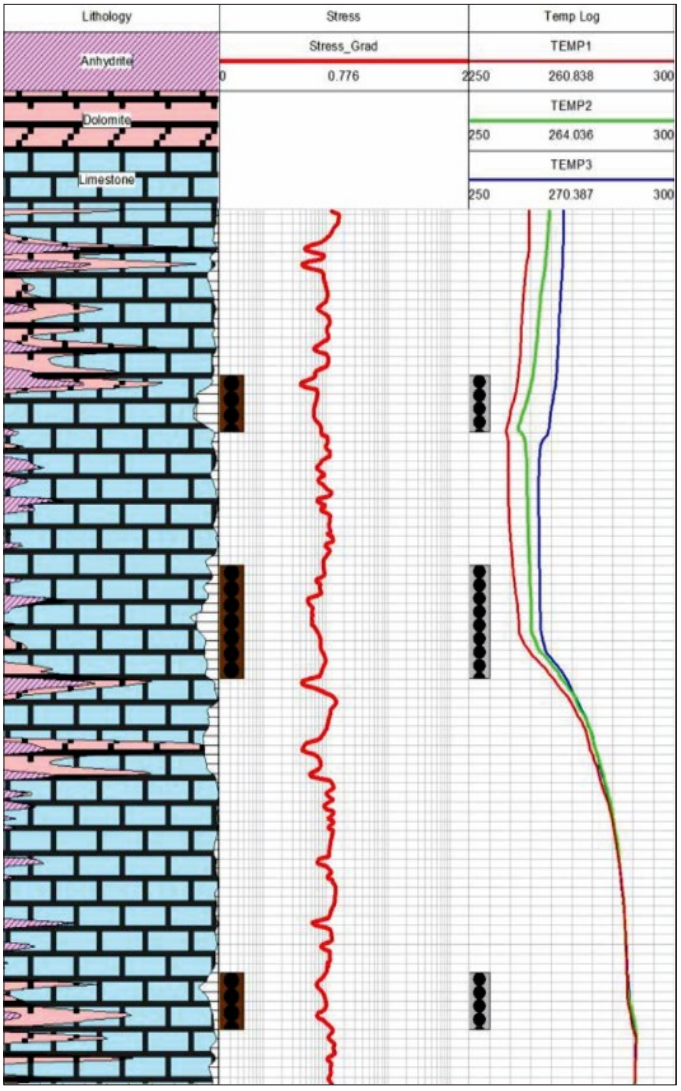

Fig. 13. Lithology, perforation intervals and temperature log for Well-B used to confirm diversion success.

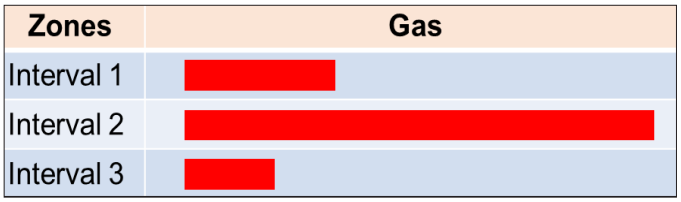

Fig. 14. PLT data processed for Well-B.

tion treatment was considered to be a further successful step toward optimizing the use of a combination of near wellbore and deep penetration novel diversions to help achieve uniform stimulation where perforations are spaced out or where long perforation intervals need to be efficiently treated, which are common conditions for acid stimulation completion designs in the area.

Well-C: Sandstone Proppant Fracturing

Well-C is a horizontal well completed in a sandstone formation. It has a sliding sleeves completion in the open hole section and was designed for multistage stimulation, with each stage isolation achieved by use of swell packers. Seven fracture ports were placed across the horizontal section, and the interval was designed for seven proppant stimulation treatments.

The ultimate goal for such multistage stimulation is to cre-

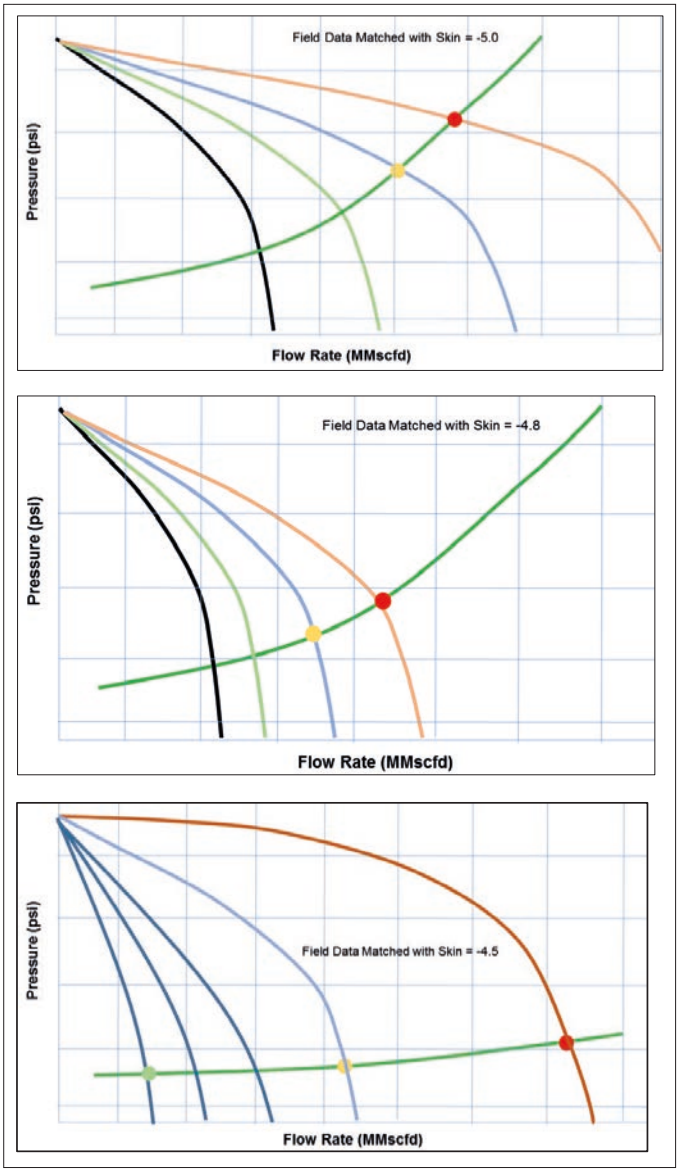

Fig. 15. Production nodal analysis and production match, Well-B.

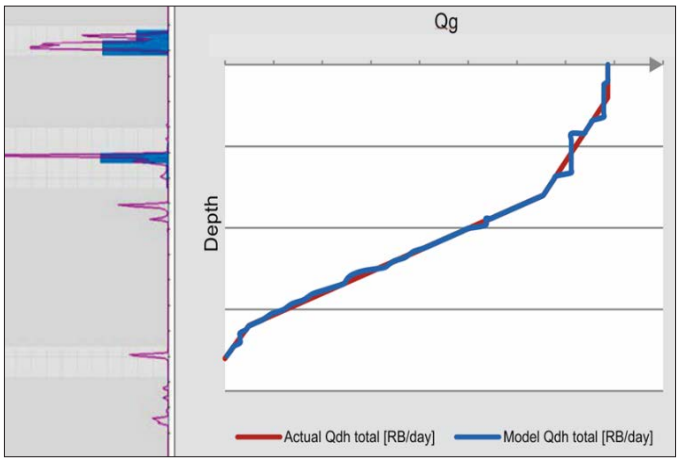

Fig. 16. Permeability thickness match for reservoir quality estimation, Well-B.

ate a fracture network across the horizontal section, generating a large-scale reservoir contact area and maximizing recovery from the microdarcy formations that some of these wells will produce from. The production level is in direct relation with the fracture network volume; however, designs for such wells require careful evaluation of reservoir characteristics and surrounding area development. Well spacing, lateral length and number of stages are a few factors to be considered[2].

To treat a long interval efficiently, the conventional fracturing techniques require stages to be closely spaced with an increased stage count per well. Stage spacing can be significantly reduced for an open hole completion by using near wellbore diverter material in conjunction with a CPP procedure. Use of near wellbore diverter particulates greatly assists in boosting net pressure during stimulation by plugging off predominant stimulated intervals and ensuring uniform treatment of the designed number of fracture initiation points of a particular stage. This novel approach leads to optimized stage spacing and efficient treatment of all sweet spots.

The average distance between packers for Well-C was approximately 270 ft, with some stage intervals slightly longer than others. Stimulation with near wellbore novel diversion was proposed for the first stage with a total open hole interval length of 335 ft. The design considered two stimulation proppant cycles divided by a near wellbore novel diversion intra-stage. CPP was incorporated in each cycle to eliminate pressure dissipation during the breakdown stage, caused by the opening of fissures and natural fractures that can occur in open hole fracturing, Fig. 17. A total of 604,000 lbm of high strength 30/50-mesh proppant was successfully placed in the formation in two separate cycles. Similar to the previously described cases, the pumping rate was dropped down to 10 bbl/min at the surface and bottom-hole stages of the near wellbore novel diversion. Once the diversion effect was observed, the pumping rate gradually increased to 47 bbl/min. Maximum proppant concentration designed and achieved was 4 lbm/gal, Fig. 18. As indicated in the figure, the WHP value changed after the diverter dropped while

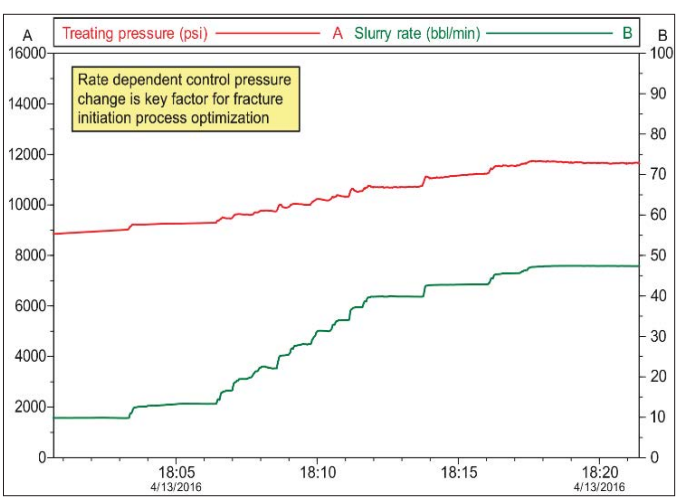

Fig. 17. Control pressure pumping procedure assisting near wellbore novel diversion on new initiation points development, Well-C.

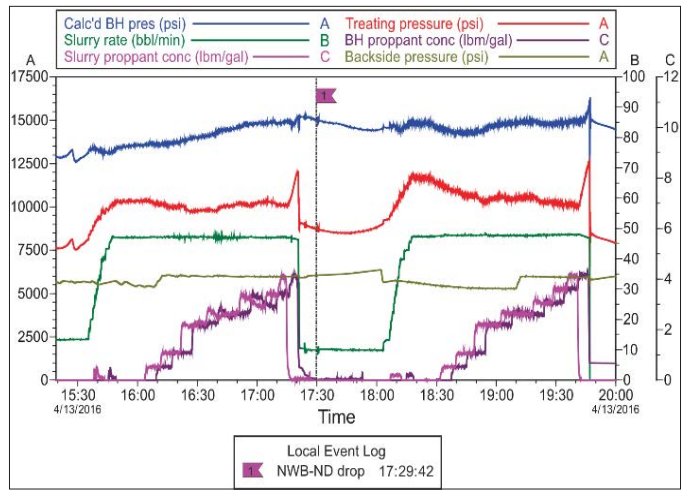

Fig. 18. Two cycles of proppant placement, divided by the near wellbore novel diversion intra-stage, Well-C.

pumping the second cycle at the same slurry rate of 47 bbl/min, indicating a change in bottom-hole conditions caused by the novel diversion's effects near the wellbore.

Well-C has since become the best producer in the area, with high WHP production data, which was used to history match and evaluate the impact of each multi-cycle stage. Each stage was pressure matched, and the fracture parameters of each and a single fracture obtained was used in the production model. Taking into account the multi-cycle treatment performed on the largest open hole section of the lateral, fracture geometries cre-

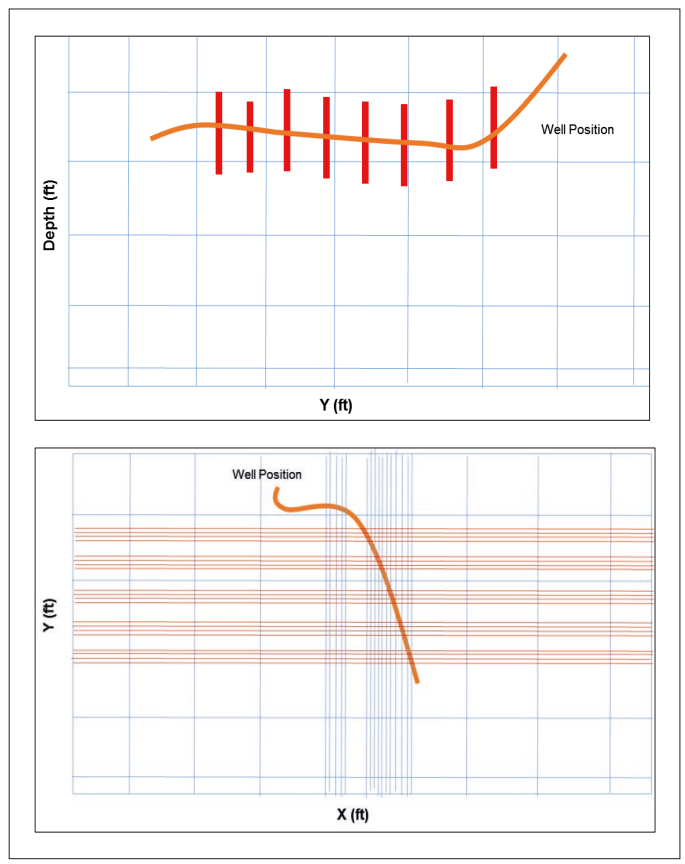

Fig. 19. Fracture grid model built upon eight matched fracture geometries created during multistage stimulation of Well-C.

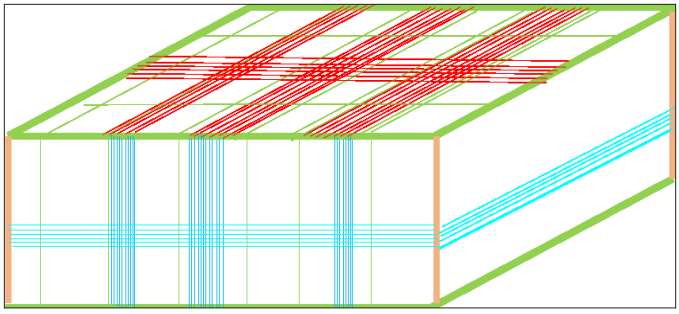

Fig. 20. Fracture reservoir grid simulation cube built for a production history match of Well-C.

ated by each cycle were modeled and matched as two separate fractures along the lateral within the interval isolated by a toe swell packer.

Reservoir data, along with matching output, for a total of eight fractures was input into a grid-based production simulator to build a model of the fracture network that developed for the reservoir after multistage stimulation was performed on Well-C, Fig. 19. This fracture reservoir grid model, Fig. 20, was then used to perform a history match and confirm each fracture contribution into the overall production value.

Figure 21 demonstrates a production simulation curve matched close to the field data, confirming accurate estimation of fracture geometries and conductivities. A period of 40 days for production history forecasting was necessary to evaluate additional fracture effects. Figure 22 demonstrates the relative production of the extra fracture generated by the multi-cycling stage — eight fractures placed in seven stages — in comparison to a conventional stimulation scenario where seven fractures would have been placed. A 10% increase in cumulative production value was achieved using near wellbore novel diversion in the first stage of the treatment, a result of higher stimulated reservoir volume, which otherwise would not have been achieved in a conventional treatment. This is a successful example of completion optimization that significantly reduces costs by eliminating the number of stages and increasing stage spacing.

CONCLUSIONS

The combination of a novel diversion technique and CPP has proven to be very successful in achieving uniform stimulation across the completion intervals in numerous wells that exhibited a high range of formation heterogeneity. Unless each open interval is treated separately, a conventional fracturing fluid will only stimulate the developed sections, leaving much of the hydrocarbon behind in the pipe. Results demonstrate the very positive impact, contribution and benefits of applying novel diversion and CPP techniques.

- Multiple perforation clusters can be effectively treated using novel diversion technology.
- Novel diversion technology uses biodegradable material to successfully seal perforations, and its effectiveness has been proven by the post-job diagnostics log and well performances.
- Far-field chemical diverters can be effectively replaced by deep penetration novel diversion technology.
- Novel diversion technology enables faster completion operations at a lower cost by helping to reduce the number of pumping operations during MSF.
- The novel diversion technology facilitates the fracturing of longer intervals, reducing the number of perforation runs and isolation plugs.

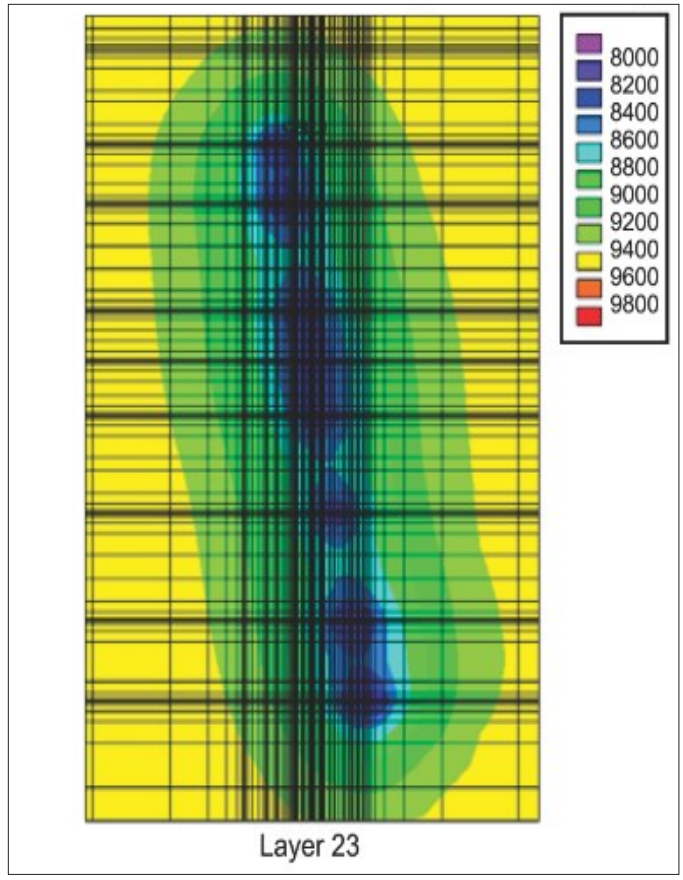

Fig. 21. Simulation of a 36-day pressure transient along a stimulated lateral, Well-C.

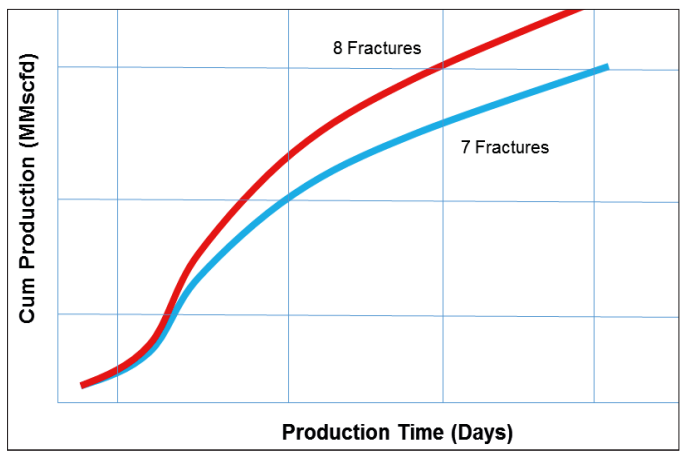

Fig. 22. Cumulative production increase as an effect of the multi-cycling stage, Well-C.

- Rapid degradation of the particulates is ideal for lower reservoir pressure environments, which can quickly produce back the injected fluids and subsequently flow hydrocarbons to the surface.
- The field applications were highly successful in both carbonate and sandstone formations, meeting the expected production rates and long-term sustainability.
- Novel diversion technology has proven successful in matrix acidizing, acid fracturing and proppant fracturing treatments, both in vertical and in horizontal well configurations.

ACKNOWLEDGMENTS

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BIOGRAPHIES

Dr. Zillur Rahim is a Senior Petroleum Engineering Consultant with Saudi Aramco's Gas Reservoir Management Department (GRMD). He heads the team responsible for stimulation design, application and assessment, both for conventional and for tight gas reservoirs. Rahim's expertise includes well stimulation, pressure transient test analysis, gas field development, planning, production enhancement and reservoir management. He initiated and championed several novel technologies in well completions and hydraulic fracturing for Saudi Arabia's nonassociated gas reservoirs.

Prior to joining Saudi Aramco, Rahim worked as a Senior Reservoir Engineer with Holditch & Associates, Inc., and later with Schlumberger Reservoir Technologies in College Station, TX, where he consulted on reservoir engineering, well stimulation, reservoir simulation, production forecasting, well testing and tight gas qualification for national and international companies.

Rahim is an instructor who teaches petroleum engineering industry courses, and he has trained engineers from the U.S. and overseas. He developed analytical and numerical models to history match and forecast production and pressure behavior in gas reservoirs. Rahim also developed 3D hydraulic fracture propagation and proppant transport simulators, and numerical models to compute acid reaction, penetration, proppant transport and placement, and fracture conductivity for matrix acid, acid fracturing and proppant fracturing treatments.

He has authored more than 100 technical papers for local/international Society of Petroleum Engineers (SPE) conferences and numerous in-house technical documents. Rahim is a member of SPE and a technical editor for SPE's *Journal of Petroleum Science and Technology (JPSE)* and *Journal of Petroleum Technology (JPT)*. He is a registered Professional Engineer in the State of Texas, a mentor for Saudi Aramco's Technologist Development Program (TDP) and a member of the Technical Review Committee. Rahim teaches the "Advanced Reservoir Stimulation and Hydraulic Fracturing" course offered by the Upstream Professional Development Center (UPDC) of Saudi Aramco.

He is a member of GRMD's technical committee responsible for the assessment, approval and application of new technologies, and he heads the in-house service company engineering team on the application of best-in-class stimulation and completion practices for improved gas recovery.

Rahim has received numerous in-house professional awards. As an active member of the SPE, he has participated as co-chair, session chair, technical committee member, discussion leader and workshop coordinator in various SPE international conferences.

Rahim received his B.S. degree from the Institut Algérien du Pétrole, Boumerdes, Algeria, and his M.S. and Ph.D. degrees from Texas A&M University, College Station, TX, all in Petroleum Engineering.

Adnan A. Al-Kanaan is Manager of the Gas Reservoir Management Department (GRMD), overseeing three divisions with more than 120 engineers and technologists. He is directly responsible for strategic planning and decisions to enhance and sustain gas delivery to meet the Kingdom's ever increasing energy demand. He oversees GRMD's operating and business plans, new technologies and initiatives, tight and unconventional gas development programs, and the overall work, planning and decision making.

Adnan has 22 years of diversified experience in oil and gas reservoir management, full field development, reserves assessment, production engineering, mentoring of young professionals and effective management of large groups of professionals. He is also a key player in promoting and guiding the Kingdom's unconventional gas program, where he has served as General Manager. Adnan also initiated and oversees the Tight Gas Technical Team to assess and produce the Kingdom's vast and challenging tight gas reserves in the most economical way.

Adnan started his career at the Saudi Shell Petrochemical Company as a Senior Process Engineer. He joined Saudi Aramco in 1997 and was an integral part of the technical team responsible for the on-time initiation of the two major Hawiyah and Haradh gas plants that currently process more than 6 billion standard cubic feet of gas per day (Bscfd). Adnan also directly managed the Karan and Wasit field developments — two major offshore nonassociated gas increment projects — with an expected total production capacity of 5 Bscfd, in addition to the new Fadhili gas plant with 2.5 Bscfd processing capacity, expected online in 2019. Adnan also served on assignment in the position of General Manager for the Unconventional Resources Group.

Prior to the inception of GRMD, he was the General Supervisor for the Gas Reservoir Management Division under the Southern Reservoir Management Department for 3 years, heading one of the most challenging programs in optimizing and managing nonassociated gas fields in Saudi Aramco.

He actively participates in the Society of Petroleum Engineers (SPE) forums and conferences, and has been a keynote speaker and panelist for many such programs. Adnan's areas of interest include reservoir engineering, well test analysis, simulation modeling, reservoir characterization, hydraulic fracturing, reservoir development planning, and reservoir management.

In 2013, he chaired the International Petroleum Technical Conference, Beijing, and in 2014, Adnan was a keynote speaker and technical committee member at the World Petroleum Congress, Moscow. In 2015, he served as Technical Conference Chairman and Executive Member at the Middle East Oil Show, Bahrain.

Adnan received the international 2014 "Manager of the Year" award conferred by *Oil and Gas Middle East* (*OGME*) magazine for his outstanding contribution in the oil and gas industry. He also received two prestigious SPE awards: a 2015 "Service" award and 2016 "Management and Information System" award. In addition, under his direct supervision and management, GRMD received *OGME's* "Best Project Integration" award in 2013 and the Abu Dhabi International Petroleum Exhibition and Conference's "Oil and Gas Innovation" award in 2016 for its work, respectively, on the Karan and the Arabiyah/Hasbah projects, two major offshore gas projects.

He has authored more than 50 technical papers on reservoir engineering and hydraulic fracturing.

Adnan received his B.S. degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Syed Muhammad has 16 years of experience in the oil and gas industry, working in the Asia Pacific, the United States and the Middle East, specializing in downhole completion equipment. He currently works as a Completions Engineering Specialist for the Unconventional Resources Department in Saudi Aramco, where he looks into the application of new downhole technology to optimize operational frequency and recovery as well as providing operational and technical support to current Unconventional Business Units.

Syed received his M.S. degree in Mechanical Engineering from the University of Aberdeen, Aberdeen, Scotland.

Elspeth M. Crawford is a Petroleum Engineer with Saudi Aramco's Unconventional Production Engineering Division of the Well Completion Operations and Production Engineering Department. Prior to joining Saudi Aramco in 2014, she worked in the United States as a Lead Engineer for horizontal completions and stimulation in the mid-continent area. Elspeth has 10 years of experience in hydraulic fracturing design and implementation in complex unconventional horizontal wells.

Elspeth is an active member of the Society of Petroleum Engineers (SPE) and has coauthored four publications and presented papers at several conferences and workshops.

She received her B.S. degree in Chemical Engineering from the University of Mississippi, Oxford, Mississippi. In 2016, Elspeth became a licensed Professional Engineer in Petroleum Engineering.

Mohamed Khalifa is currently the Halliburton Stimulation Technical Lead in Saudi Arabia. He joined Halliburton, working in production enhancement in operations, and worked his way up from Stimulation Engineer to Senior Account Representative. Mohamed has extensive experience in production engineering, petrophysics, well analysis and stimulation evaluation, in both onshore and offshore wells. He has 15 years of experience in stimulation and well completions, including conventional and unconventional hydraulic fracturing, hybrid fracturing, high rate water fracturing, fracpac, acid fracturing, carbonate acid stimulation, sandstone acid stimulation, pinpoint stimulation for vertical and horizontal wells, AccessFrac and conductor fracture.

Mohamed received his B.S. degree in Mechanics and Evaluation Engineering from Cairo University of Technology, Cairo, Egypt.

Driss Krich started his career with Halliburton in 2006. After a 2-year period of technical training in South Texas, Oklahoma and Arkansas, he moved to Dallas-Fort Worth, TX, and held technical and business development positions supporting Halliburton Completion Tools in the mid-continent USA, including working with Versa Flex® liner hangers, service tools and completion products.

In early 2011, Driss helped with the execution of completion projects in Poland and Western Siberia. He joined the Halliburton Easy Well Sub-Product Service Line and became part of the Carrollton, TX, and Stavanger, Norway, technology team to develop swell packer solutions tailored to satisfy the need of multistage completions in the Saudi Arabia market.

In November 2012, Driss joined the Saudi Completion Team as a Technical Advisor for multistage completions and led the deployment of multistage fracturing technologies with successful trials within the Reservoir Management Department (RMD) and the Gas Reservoir Management Department (GRMD).

In May 2014, he became the Account Manager for the Southern Area ('Udhailiyah), helping with new technologies deployment and lump-sum turnkey rig and rigless operations. Currently, Driss is the focal point for all of Halliburton's Product Service Lines supporting RMD and GRMD.

In 2006, he received two B.S. degrees, one in International Business and the other in Mechanical Engineering, from Oklahoma State University, Stillwater, OK.

Mohamed Zeghouani is a Senior Stimulation Engineer at Halliburton, with more than 10 years of experience in oil and gas reservoir stimulation, production operations, and petroleum engineering support. After 5 years of working in coiled tubing engineering, in which he received several internal awards for successful achievements, Mohamed moved to fracturing engineering, where he was involved in the initial shale gas project in Algeria as a focal point for coordinating the integrated solutions for the main oil and gas operator in Algeria.

In 2014, Mohamed joined Halliburton's Fracturing Team in Saudi Arabia and worked mainly in south Ghawar. He also served as the Senior Fracturing Engineer for unconventional stimulation treatments in remote locations. Mohamed is currently part of the Halliburton Tech Team working with Saudi Aramco's Gas Reservoir Management Department. He has extensive technical knowledge and experience in stimulation, conformance, reservoir engineering and new oil and gas industry technologies such as diversion, channel fracturing, pinpoint stimulation and water shutoff. Mohamed has total responsibility for Saudi Aramco's oil and gas producers operating in the major domestic onshore/offshore basins.

In 2003, he received his B.S. degree in Engineering from the Algerian National Institute of Hydrocarbon and Chemistry, Boumerdes, Algeria.

Integrated Off-Bottom Cementing and Inflow Control Device System: Design toward Well Delivery Optimization

Mohammed A. Al-Madan, Mazen Bu Khamseen, Hedy Suherdiana and Ahmad M. Al Abdulmohsen

ABSTRACT

Off-bottom cementing (OBC) operations are unique to Saudi Arabia. OBC also represents one of the most challenging types of drilling and workover operations when the system is deployed in combination with inflow control devices (ICDs) across horizontal sections. In a conventional ICD system, OBC requires an inner string with packer setting tools for setting the open hole packers, and to have 100% circulation at the bottom of the completion, with the means to wash down any tight spots. As a consequence, this introduces additional issues such as health, safety and environment concerns, logistics complexity and extra rig time. The inner string also increases the ICD completion string weight, creating more drag and increasing the risk of getting stuck while deploying the system in the horizontal section.

The multitasking valve (MTV) feature in the upgraded ICDs offers safe, simple and cost-effective deployment in operations involving OBC. That is because the MTV allows the OBC system to be deployed without the need for an inner string. This will positively impact the deployment by simplifying the complexity in the rig operation while still achieving 100% circulation at the shoe. Additionally, all the hydraulically activated equipment, such as the liner hanger packer, open hole mechanical packers, etc., can be pressurized and set simultaneously. Furthermore, without the inner string, the ICD completion will weigh less in the horizontal section, resulting in less friction and drag to reach total depth. The MTV feature provides an opportunity to deploy the ICD system and the OBC liner system together in one trip.

This article will discuss the first deployment of a combined ICD system with an OBC system during a workover operation in a historical oil producer in the Kingdom of Saudi Arabia. The merged system was successfully deployed to depth and cemented off-bottom while saving approximately 40 hours of rig operation time.

INTRODUCTION

In wells where an off-bottom cementing (OBC) liner is required to cover non-targeted formations above the production zone, two methods of deployment can be used: the "one-trip deployment system" and the "two-trip deployment system." The difference lies in whether or not the OBC components are deployed in a single trip along with the inflow control device (ICD) completion as "one go" or in a second trip with an inner string in the previously deployed ICD completion[1].

The one-trip OBC ICD completion, Fig. 1, doesn't allow an inner string application. Therefore, circulation while running in hole is ineffective, which can cause deployment problems.

The two-trip OBC ICD completion was then suggested to solve the problem. The idea was to split the completion into upper and lower completions, with the lower ICD completion dropped off inside the open hole horizontal section with a setting sleeve, Fig. 2.

This two-trip OBC ICD completion utilizes an inner string, circulating system and open hole packer setting tool. This enables 100% circulation from the shoe during deployment of the

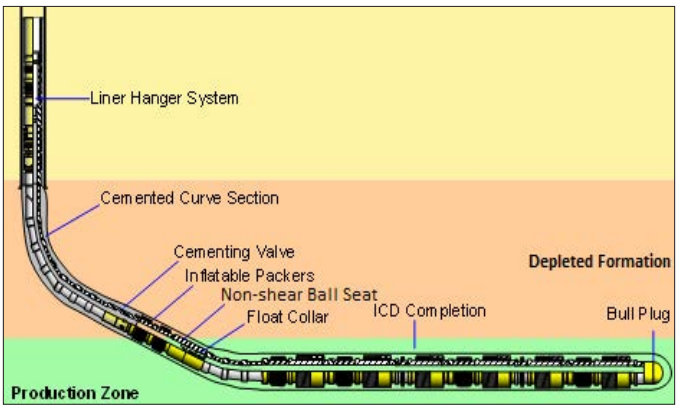

Fig. 1. One-trip OBC ICD completion.

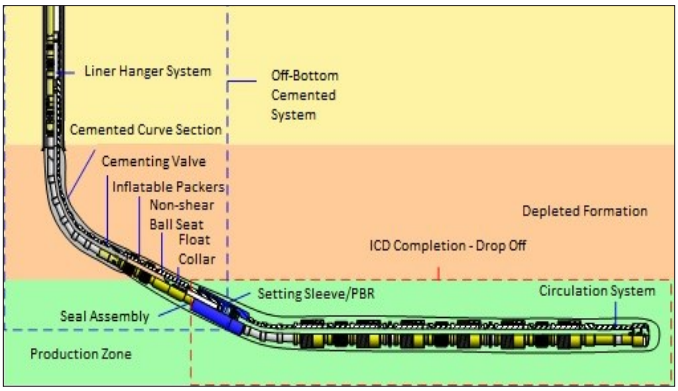

Fig. 2. Two-trip OBC ICD completion with circulating system.

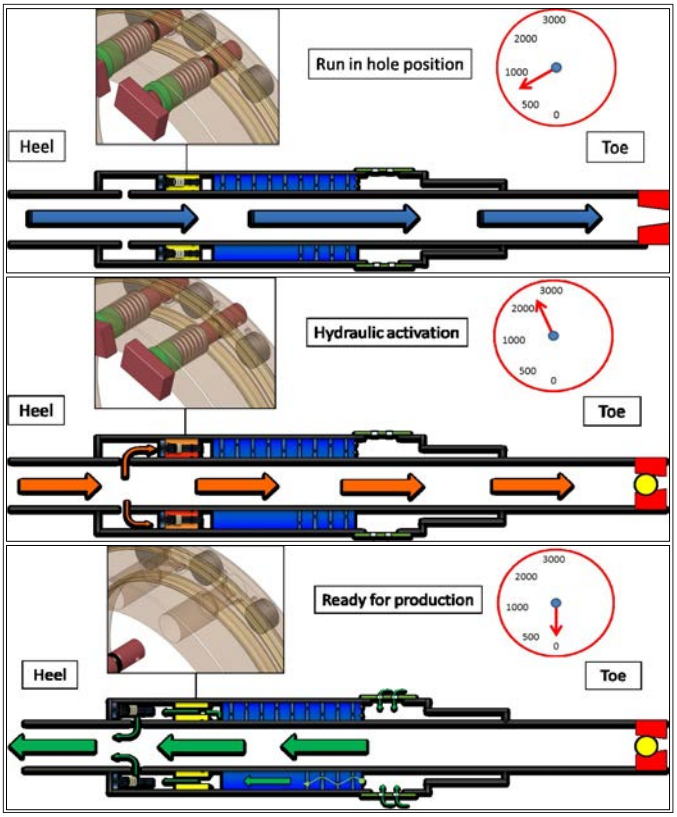

Fig. 3. MTV operation sequence.

lower ICD completion, although circulation rate is limited due to the need for pumping fluid through tubing with a small internal diameter (ID).

Then the ICD completion was upgraded with a multitasking valve (MTV) that allows the lower completion to be deployed without an inner string while still achieving 100% circulation at the shoe, which smoothes operations and saves rig time — up to 24 hours[2]. The MTV temporarily blocks the communication between string and annulus while running in hole, Fig. 3. Once the completion reaches the setting depth, the MTV is activated by hydraulic pressure. All hydraulically set equipment can also be set at this point. The MTV plugs are released once pressure is bled off from the system. The spring attached on the plugs has enough force to open the valve at an overbalance up to 90 psi.

Figure 4 shows the two-trip OBC completion combined with the upgraded ICD MTV. The circulating system utilizes a wellbore isolation valve, which also acts as a ball seat. The wellbore isolation valve has a unique flow path, which will be permanently closed once the ball lands on the ball seat and is pressurized. This enables setting all the open hole packers at once with a single ball drop.

During the run history using the two-trip OBC application, it was observed that if the hole is not stable or has areas of washout, it can be challenging to string the seal assembly of the OBC kit into the ICD completion polished bore receptacle[1].

In view of the benefits of the MTV feature, it was therefore decided to combine the separated two-trip deployment once again into a single system. The MTV feature provides important functions for the one-trip OBC ICD completion; the ability to perform 100% circulation from the shoe and the ability to set all hydraulic downhole tools with one setting ball.

COMPLETION DESIGN

Figure 5 shows the integrated system, which eliminates the seal assembly and setting sleeve. The float collar was also removed to provide passage for the setting ball to land on the wellbore isolation valve located near the end of the completion string, above the float shoe. The non-shear ball seat position has been moved below the cementing valve, which closes to provide a cement barrier from inside after dropping a second ball. The non-shear ball seat ID was enlarged to accommodate the pass-through of the 1.250” setting ball, while still being able to hold the 1.500” ball for a cement barrier.

FIELD TRIAL SUMMARY AND RESULT

The well chosen for deploying the first integrated one-trip OBC ICD completion with a MTV was one of the historical wells in Saudi Arabia; the discovery well of the largest field in the world. It was drilled in July 1948 as an exploration well with a 7” casing. After a successful perforation job, the well was converted to an oil producer and completed with 2⅞” tubing. A 7” downhole packer with 3½” and 4½” tubing was set during the first workover that took place in July 1973 to replace the corroded 2⅞” tubing. The well was kept in production until

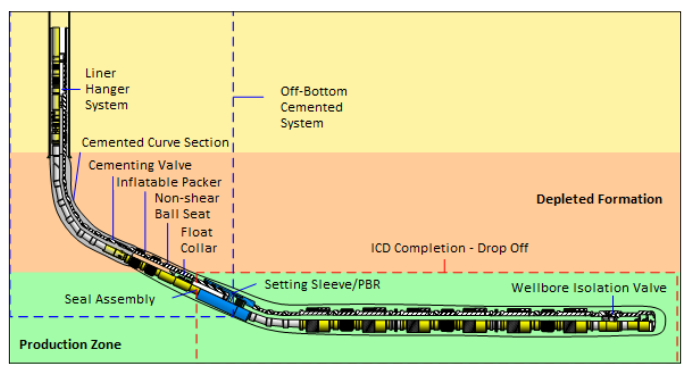

Fig. 4. Two-trip OBC ICD completion with circulating system and MTV.

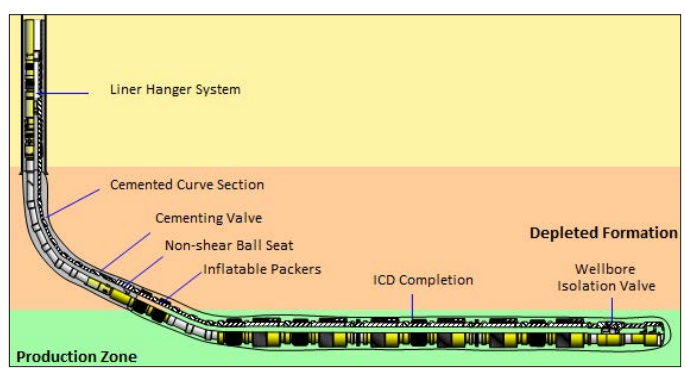

Fig. 5. Integrated OBC ICD completion with MTV.

Parameters	WELL-X OBC 1-TRIP W/MTV	WELL-Y OBC 2-TRIP W/MTV	WELL-Z OBC 2-TRIP W/INNER STRING
Total Depth	10,600	10,600	10,900
Horizontal Length	3,000	2,700	2,400
ICD Quantity	9	9	9
Mech. Open Hole Packers	4	3	2

Table 1. Compared OBC well parameters

mid-2012, when high tubing casing annulus (TCA) pressure was observed in addition to a water cut increase. A workover operation was proposed to salvage the high TCA pressure and sidetrack the well to restore its productivity.

Re-entering a well drilled about 65 years ago was a challenge, and deploying the integrated OBC ICD system for the first time worldwide made it an important job. In the last quarter of 2013, the workover operation was commenced by killing the well. The well was de-completed, and the motherbore was plugged back to the whipstock setting depth. A window was then opened, and a 6⅛" hole was drilled to target depth with approximately 3,000 ft drilled horizontally. Prior to running the integrated downhole completion, a stiff reaming assembly was run to clean out any tight spots, and a wiper trip was performed to confirm that the directional hole was in good condition. A lubricant pill was spotted, and the stiff reaming assembly was pulled out of the hole.

The proposed completion, which consisted of a wellbore isolation valve, nine ICDs with MTV, four mechanical open hole packers and five small swell packers plus the OBC line system kit, was picked up, drifted and labeled. Getting this completion to the target depth across more than 5,000 ft of open hole in an area known for differential sticking was a big concern, as any delay would lead to a stuck completion. Reducing the connection time between stands, filling the string using a hose as it was run in hole and utilizing special centralizers that have a lower friction factor were the key factors in getting the completion to target depth.

The completion equipment reached target depth after 18 hours. The hole was circulated clean at 3 bpm and 450 psi, and displaced to brine. A biochemical mud treatment was pumped to be spotted across the ICD completion. A 1.250" setting ball was dropped, and chased with a high viscous pill and brine.

The ball landed at the wellbore isolation valve, and pump pressure was increased to 1,600 psi to set the liner hanger. The hanger was set and confirmed with 20,000 lb slackoff. Pressure continued to be increased to 2,000 psi to set the inflatable packers. Pressure was brought up to 2,800 psi to set the me-

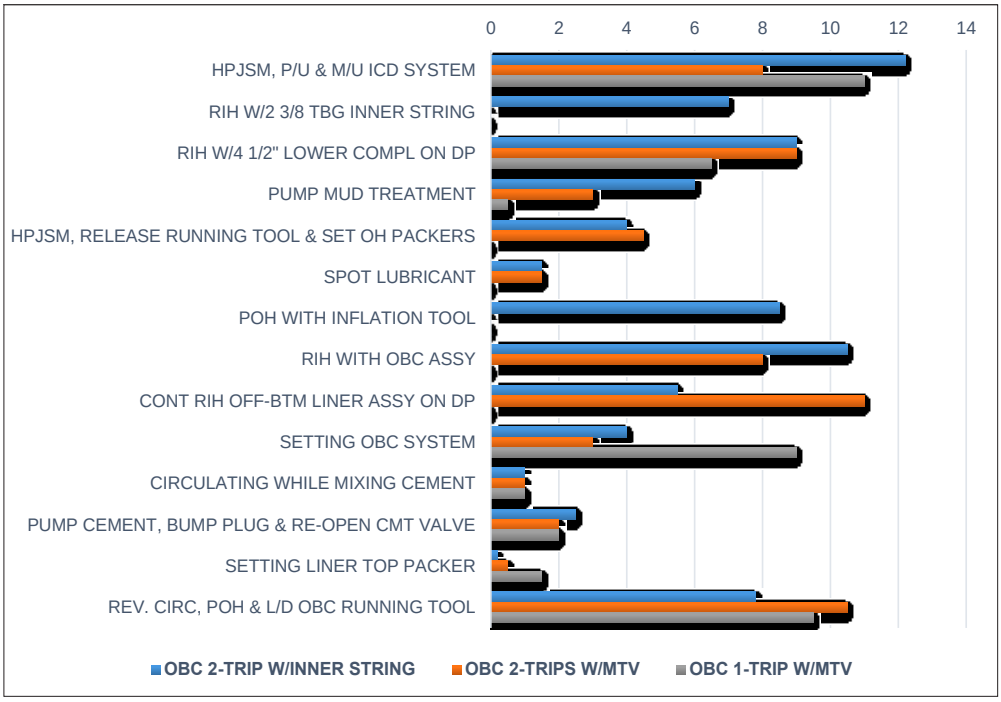

Fig. 6. Rig time operating hours for each OBC system.

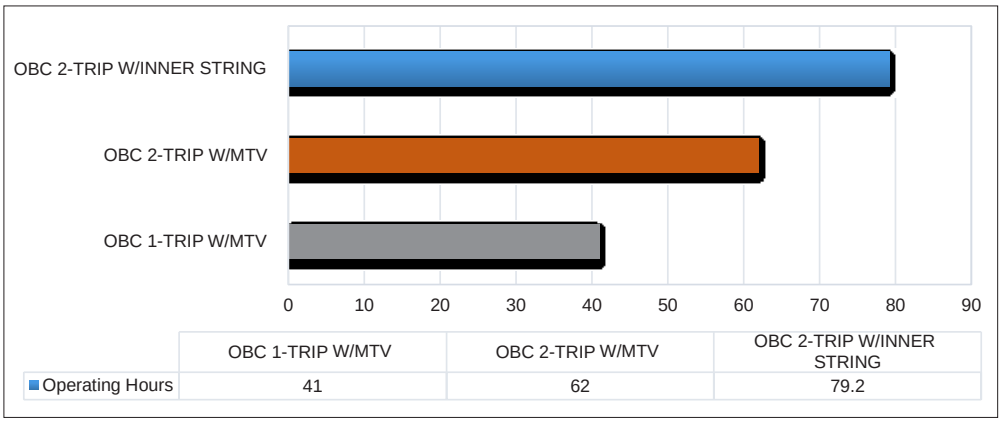

Fig. 7. Rig operating time comparison of three OBC ICD completions.

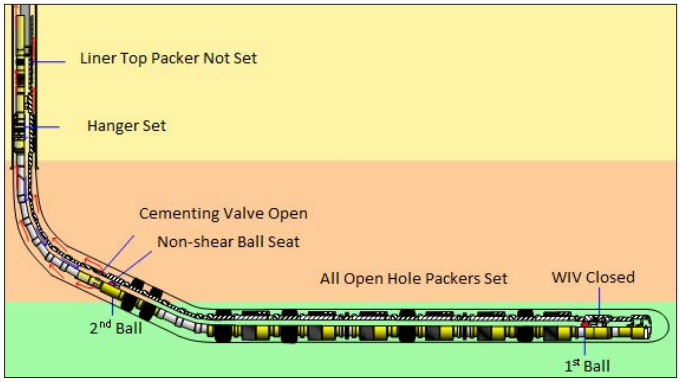

Fig. 8. Circulation path from the cementing valve after dropping the second ball for the cement barrier.

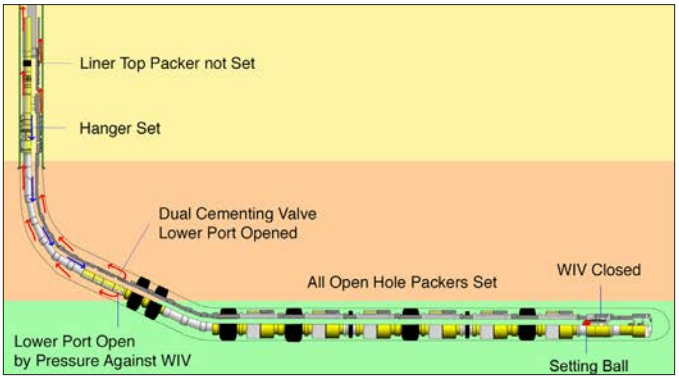

Fig. 9. Dual cementing valve with lower port opened by pressure.

chanical open hole packer, to activate the MTV and to release the hydraulic liner hanger setting tool. The liner hanger setting tool release was confirmed by pickup. The running string was slacked off by 20,000 lb, and pressure was increased to 3,100 psi, opening the cementing valve. Circulation was resumed through the cementing valve. A second ball — 1.500" outer diameter — was dropped and chased the high viscous pill as a marker. The hole was displaced back to mud, and the marker pill showed at the surface, confirming circulation was coming through the cementing valve.

Prior to the cementing job, a surface cementing line was tested to 4,000 psi, while 60 bbl of 123 pcf cement was mixed. The cementing job started by pumping a spacer followed by the cement slurry. A dart plug was dropped and displaced consecutively with a spacer, followed by mud, then the spacer and finally mud. Once the plug landed on the cementing valve, pressure was increased to 1,000 psi above the 700 psi flowing drillpipe pressure. There was no back flow, which confirmed that the cementing valve was closed. The liner top packer was set, the running tool was strung out of the liner top packer, and reverse circulation was performed to clean out the spacer and contaminated cement. The running tool was pulled out of hole, and the job was completed. After the cementing plug and non-shear ball seat was drilled out, 320 ft of contaminated cement was found below the non-shear ball seat. The first ICD was located 400 ft below the non-shear ball seat.

COMPARISON AND GAINED VALUE

Table 1 shows the compared parameters of the three wells chosen for workover with the OBC ICD system. These three wells were drilled and completed by the same rig.

Figures 6 and 7 show the rig time operating hours for each OBC ICD system deployment. It clearly shows the OBC one-trip with MTV eliminated all the added operating time required by the inner string, the need to set the open hole packers with an inflation tool and a second trip. For the mud treatment, pumping time is significantly reduced in the OBC one-trip with a MTV.

DISCUSSION

Prior to deployment, it was acknowledged that no positive indication could be received that the 1.500" ball had landed on the non-shear ball seat below the cementing valve. The lower completion will already be a closed system after permanently closing the wellbore isolation valve, with circulation now coming through the cementing valve, Fig. 8. The only way to minimize the uncertainty was to shorten the distance between the non-shear ball seat and the cementing valve.

FUTURE DEVELOPMENT

To have the ability to seal off the ICD completion from cement in the string, a dual cementing valve has been developed. Fig-

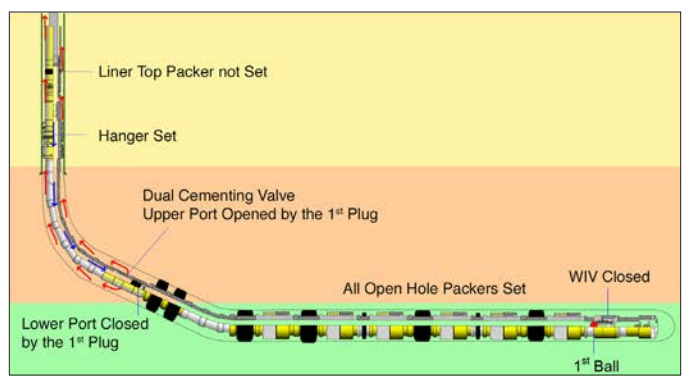

Fig. 10. Dual cementing valve with lower port closed by plug and upper port opened.

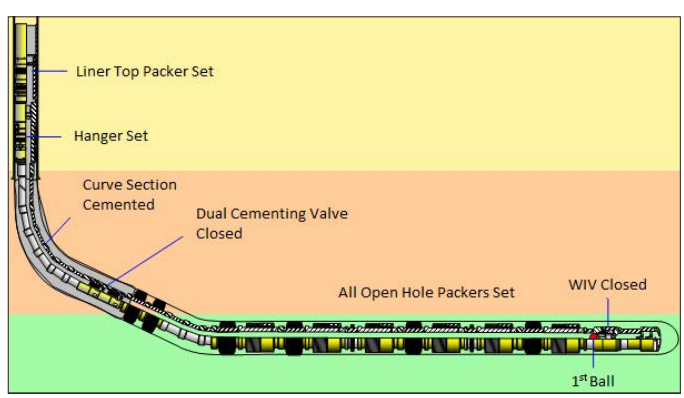

Fig. 11. Dual cementing valve closed and curved section cemented.

ure 9 shows the lower port of the dual cementing valve, which will be opened by pressure against the wellbore isolation valve. After regaining circulation through the port, the first plug will be dropped. This plug will close the lower port, while also providing positive isolation for the ICD completion against cement intrusion from inside the completion string, Fig. 10. The dual cementing valve's upper port will be opened by pressure against the first plug, which will provide the path for cementing. Once cement is pumped, a second plug will be dropped and the upper port will be closed, Fig. 11.

CONCLUSIONS

1. The integrated OBC ICD completion successfully optimized well delivery by eliminating almost 40 hours of rig operating time.
2. The MTV on the ICD makes a major contribution to the system, allowing all hydraulic activations and settings to happen at one time.
3. The current system has the limitation of not having a positive indication that the second ball has landed on the non-shear ball seat as a second barrier, which could result in cement invading the lower completion.
4. Future development of the dual cementing valve will provide positive isolation for the ICD completion from the cement inside the completion string.

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BIOGRAPHIES

Mohammed A. Al-Madan joined Saudi Aramco in 2007 as a Workover Engineer in the Drilling & Workover (D&WO) Department. During his career, he has worked on multiple critical projects, including leading several innovative trials that helped in salvaging wells, and he developed optimization workover procedures that led to significant cost reductions. Recently, Mohammed was appointed to be a Workover Engineering Unit Supervisor (A) for offshore workover engineering operations.

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In 2009, he joined Weatherford as a Field Engineer in the Liner Hanger Department, performing liner hanger jobs and ICD jobs. In 2011, Ahmad went back to Baker Hughes as a Field Engineer and became an Account Manager in the Sales Department at the beginning of 2012. He was then assigned to the Aramco Oil Workover Department, where he was responsible for sales, marketing and developing the business.

In 2014, Ahmad moved to 'Udhailiyah as an Account Manager for the Saudi Aramco Gas Drilling & Workover Department.

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Innovative Testing of Milling and Wellhead Freeze Implemented on Offshore High Rate 10,000 psi Gas Well

Robert D. "Dixie" Haymes Jr., Khalid Imtiaz and Carlo Mazzella

ABSTRACT

A stuck 8.635" 10,000 psi Inconel 925 back pressure valve (BPV) required milling out, and a specialized testing apparatus was needed to validate the mill design. Removing the compromised BPV mandated that an ice plug freeze capable of withstanding a 10,000 psi test be placed at an 18¾" Unihead to serve as a well control barrier on the high-pressure sour gas well. The design development and testing process as well as the field results of actions taken to mill the BPV and apply the ice plug freeze are presented.

Mill machine lathe tests were conducted to determine the preliminary cutting structure for the mill and the mill profile. The test apparatus simulated milling an 8.635" Inconel 925 BPV stuck in a 9⅝" Inconel 725 tubing hanger. A test stand with a 26" outside diameter (OD) casing and 9⅝" OD inner casing was constructed and double wrapped with 500 ft of ¾" helical coil to simulate the freezing of an 18¾" Unihead, with 10,000 psi pressure integrity inside the 9⅝" tubing.

The rectangular inserts selected for cutting the material during the milling machine tests of one mill design — to be used for both the hanger and BPV — created excessive vibrations, high torque, chipped inserts and slow milling. The first test revealed the inability of one mill to cut two materials and profiles, in addition to limitations posed by the available milling parameters. The cutting matrix was changed, and two distinct mills were designed and specialized for each profile. The test fixture was also modified to enable a broader range of milling parameters and centralization in a more robust apparatus. The two mills successfully milled the required profile in the second test, and the optimal milling parameters were obtained.

The ice plug test was performed on a vertical stand of 26" OD casing, wrapped with helical coil, and 9⅝" OD inner casing. The annulus and tubing were filled with water and liquid nitrogen (N_2) that was free flowed from tanks through a 2" hose. The mass was cooled to -70 °F with an ambient temperature of 86 °F and repeatedly pressure tested to 2,000 psi and 10,000 psi. The test provided positive proof of the ice plug's integrity as a well control barrier for the large diameter application.

The innovative testing for the mill and freeze applications provided needed information for success in the field. A BPV of this size, material and design had never been milled before. This was also the first time a freeze of this size and pressure rating had been placed and tested to 10,000 psi. The project highlighted the value of off-site, pre-job validation testing as opposed to the on-site trial and error approach, which can prove costly and ineffective.

INTRODUCTION

In a high-pressure sour gas well, an 8.635" 10,000 psi Inconel 925 back pressure valve (BPV) was improperly set above the 9⅝" Inconel 725 tubing hanger's BPV locking grooves. During pressure testing of the blowout preventers (BOPs), the improperly set BPV was unintentionally pressed down into the tubing hanger profile with 500,000 lb of force. Subsequent efforts to retrieve the BPV with a coiled tubing and slick line conveyed pulling tool were unsuccessful, so access to the tubing was lost and the completion operations ceased. The equalizing cove was also removed during the attempts to recover the BPV, so the BPV could no longer serve as a well control barrier.

The options for removing the BPV were either to attempt pulling it along with the tubing hanger or to mill over the outside diameter (OD) of the BPV and the internal diameter (ID) of the tubing hanger to remove the material pressed together. A BPV of this size, material and design had never been milled before, so milling machine tests were conducted to develop the mill design, and a specialized test apparatus was constructed to simulate the milling of the BPV to confirm the mill design and potential milling parameters.

The pre-job milling test validated the mill design, and the on-site milling of the BPV in the field was a success, although challenges were encountered during both phases. The pre-job milling test's validation of the mill design's capability to cut the material provided confidence for overcoming the obstacles in the field.

The nipple down configuration of the wellhead tree and nipple up configuration of the BOP required an additional barrier to be placed in lieu of the compromised BPV. An ice plug freeze was chosen as the replacement barrier. It was to be placed across the 26" OD of the 10,000 psi Unihead wellhead body and the ID of the inner 9⅝" tubing string. The ice plug would also serve as the initial test plug for the BOP nipple up pressure

test, given that the normal wellhead test plug could no longer be set due to the stuck BPV.

The 10,000 psi rated ice plug freeze underwent a test to prove it as a well control barrier for a diameter this large. A vertical test stand was built and wrapped with a helical coil to free flow nitrogen (N_2) and apply an ice plug, which was pressure tested to 10,000 psi. The execution of the freeze on the actual wellhead was successful, but did require more time than expected due to the presence of unknown fluids inside the tubing that influenced the required freezing temperature. This challenge was overcome by extending the freeze area and the time duration to freeze, while also recognizing that ice plug compaction was impacting the pressure test.

Fig. 1. Milling machine test.

Fig. 2. Four-blade mill used for the milling machine test.

MILL DESIGN THEORY

The mill design objectives were to mill 3" of the Inconel 725 tubing hanger ID recess to the top of the BPV and then mill vertically down 3.56" concurrently over the outer diameter of the Inconel 925 BPV body and inner tubing hanger ID. The unique geometry of the tubing hanger and BPV required different milling actions, and the side and deep groove milling posed uncertainties. In addition, prime consideration was given to the cutting matrix due to the difficulties associated with machining Inconel, which are well documented, and the fact that in this instance two different grades of Inconel had to be milled.

The inherent properties of the nickel alloys, which make them suitable for high temperature and high strength applications, in addition to offering excellent corrosion resistance, work as a disadvantage when it comes to material removal through milling. Although the properties, and therefore machinability, change from one Inconel grade to another, all have an austenitic structure at the crystalline level. This structure is a highly ductile material with a tendency to harden during machining or similar processes. The plastic deformation that occurs with the application of cutting forces not only hardens the material for subsequent cuts but also produces a "gummy" machining behavior. The ability of Inconel to sustain a high strength at elevated temperatures means that it is stronger at chip forming temperatures and thereby requires comparatively higher cutting loads. For the same

Fig. 3. First full-scale first test apparatus.

Fig. 4. Close-up of first full-scale mill test apparatus.

Fig. 5. Full-scale test fixture with mill.

Fig. 6. Full-scale test fixture.

Fig. 7. Full-scale test's nine-blade mill.

reasons, the material removed by a machining operation on Inconel is continuous and tough. Also, the lower thermal conductivity of Inconel and abrasion from carbide, titanium and aluminum inclusions may result in high temperatures at the cutting edge. All these factors can have a detrimental effect on the cutting matrix, resulting in vibrations, high wear or blunting, chipping, notching, burning and breakage.

DESCRIPTION OF PROCESS AND APPLICATION

In light of these factors and the special circumstances of the application, a unique mill test design approach was followed. Initially, a scaled version of the preliminary concept mill was mounted on a milling machine, Fig. 1, and a test run was made on an Inconel 925 material piece to assess the cutting efficiency of the chosen rectangular inserts.

A scaled down, 3½", four-blade mill, Fig. 2, was chosen, due to the limitation of the milling machine, to generate proportionate torque to that of a full-scale test. The machine shop test was used to obtain a preliminary design concept and initial working parameters for a full-scale test.

Later, a full-scale milling apparatus was erected in Lafayette, LA, to test the milling design. The first series of full-scale tests was conducted using an apparatus that consisted of a 16" OD riser fixed on top of a 3 ft × 6 ft test stand, Figs. 3 and 4. A small, round open-top tank was welded onto the base of the test stand to house the tubing hanger and BPV fixture, and to contain the milling fluid. A power swivel, 10 ft long, with a 6¼" OD Kelly valve, and a nine-blade mill were suspended from a crane and lowered into the test fixture to conduct the milling test. The swivel supplied rpms to the mill, and the Kelly valve was used for the weight on mill (WOM). A small pump was used to circulate fresh water at 15 gallons per minute (GPM) through the mill to cool the inserts and remove the milled material.

The test fixture, Figs. 5 and 6, which was fixed to the bottom of the test stand, matched the scale and materials of the BPV and tubing hanger; however, the detailed features of the BPV were not machined into the fixture as they were not deemed necessary. The nine-blade mill, Fig. 7, with an 8.97" OD and 7.30" ID, was to mill down 3" vertically through the 0.1525" thickness on the ID recess around the circumference of the tubing hanger to the top of the 8.635" OD BPV. The mill would then cut both the tubing hanger 0.1525" ID and 0.669" of the outer BPV OD to a maximum length of 3.56", stopping just short of the 3.65" BPV fishing neck retaining lug. The ID of the mill was set at 7.30" so it would not mill the 6.98" OD retaining lugs.

The lessons learned on the first milling machine full-scale test were applied to adjust the design in the second phase of testing. A second milling machine test, Fig. 8, was conducted on the new mill design, and a more robust full-scale test apparatus was used to validate the design and obtain workable parameters for the actual field job.

For both the scaled and actual size tests, rectangular and square carbide inserts with a chip breaker profile were chosen. The chip breaker profile helps in breaking a continuous chip into smaller pieces, allowing them to be deflected and circulated away from the cutting edge. To create a better cutting edge, the sequence of inserts, in a combination of rectangular and square inserts, was reversed on consecutive blades. Above the cutting edges, a band on the OD was dressed with smooth-ground crushed carbide to facilitate stabilization of the mill during mill-

Fig 8. Second mill machine test.

ing. Water-based, standard machine shop coolant was used for the machine shop test, and the full-scale test was conducted with water as the circulation/cooling medium. Due to work hardening concerns and the high strength of the material, lower rpm speeds and feed rates were used.

The first full-scale test could not be successfully completed using the one-profile, nine-blade mill design. The tubing hanger ID recess could only be milled 1" to 1.71" after tests on two different pieces. The average milling time was 3.8 hours using 500 lbm to 3,000 lbm WOM and 45 rpm to 103 rpm. The mill exhibited excessive torque to the point of lockup, and vibrations were encountered at various rpms during the first three days of testing. A second round of testing was conducted with the first nine-blade mill design, but with the inserts dressed in a local machine shop for further experimentation. This test was also unsuccessful because of vibration and broken inserts, Fig. 9. Slower milling rpms of 20 rpm to 50 rpm were used with a larger range of WOM, from 125 lbm to 3,060 lbm, though much of the test was performed with less than 500 lbm WOM. A total of six mills were used, achieving an average milled depth of 5/16" per mill. A total of 1.90" was milled in 29 hours.

Although the cutting matrix seemed to work, removing the material, at both the OD and bottom initially, progressively slowed the milling to a stop at increased depths. Also, the cuttings were long and continuous, hinting they were not affected by the chip breaker geometry of the inserts, Fig. 10.

Based on the first full-scale test and on-site experimentation, a number of improvements were proposed. The following summarized observations helped in adjusting the design and cutting matrix in preparation for the second test.

- Carbide dressing of mills is a manual process, and no two mills manufactured to the same print are identical down to the finest details. Provision for some variance in the sizes and dressing should be considered. Placing the crushed carbide close to the insert bottom should be avoided since it interfered with the cutting edges and work hardened the metal.
- The rake and clearance angle of the inserts were sufficient; however, rectangular and square inserts have one corner edge on a given side, which are more prone to damage. Round or octagonal shaped inserts are recommended due to their stronger geometry.
- The number of prongs, i.e., cutting blades and edges, should be reduced.
- The milling bottom-hole assembly (BHA) was stabilized in the test setup to limit the side loads placed on the swivel, which increased the potential for vibrations at the cutting edge.
- Low flow rates of 15 GPM with water as the circulation fluid limited the carrying off of cuttings from the cutting edge, which appeared to create a regrinding of the cuttings. The water circulation rate should be increased to 7 barrels per minute (BPM) for the next test.
- The provision of heavier loads should be considered to test the parameters and cutting efficiency at even higher WOM. The maximum available load for the first test was 3,100 lbm.
- The base and supports for fastening of the tubing hanger and BPV fixture should be improved to reduce movement and resulting vibrations, Fig. 11.
- The milling action on the side for the tubing hanger is different from the bottom milling required for the BPV, and this resulted in vibration and broken cutters. Two different mill designs would improve the milling efficiency.

FINAL TEST AND RESULTS WITH IMPROVED MILL DESIGN AND TEST APPARATUS

On the basis of the first full-scale test results, a number of improvements were made to the mill design. The square and rectangular inserts used in the first test were replaced with octagonal inserts, Fig. 12, of carbide with a chip breaker profile. These inserts were tested on the milling machine and performed well in the removal of the Inconel 925 material. The octagonal

Fig. 9. Broken cutter from full-scale test.

Fig. 10. Full-scale test's mill cuttings.

Fig. 11. Full-scale test apparatus supports and fixture.

Fig. 12. Octagonal insert.

Fig. 13. Mill1 for cutting ID recess.

Fig. 14. Five-bladed Mill2 for cutting BPV.

inserts are an industry norm, having a sufficient history of use in milling Inconel material to justify their use. The octagonal geometry is stronger against shock loads and forces encountered during a typical milling job.

The cutting action of side milling of the tubing ID and bottom milling of the BPV groove was found to be quite different on the first test, so it was concluded that a two-step mill process, Mill1 and Mill2, would improve the efficiency. Mill1, Fig. 13, would cut the tubing hanger ID recess down to the top of the BPV, and Mill2, Fig. 14, would cut both the tubing hanger ID and BPV OD, Fig. 15, from the top with a circular groove, removing the BPV wedged into the tubing hanger and enabling the BPV to be pulled free.

The rectangular cutters were replaced with octagonal cutters to improve durability, but the cutter insert material of tungsten carbide — cement carbide — was not changed. The rake angle was reduced so it would be less aggressive. The number of blades was reduced from nine on the original mill to five for what became Mill2, to minimize the likelihood of work hardening. These new blades also had the added feature of pre-machined slots to aid precise cutter placement and redressing. The circulation passage was improved, and the crushed carbide near the inserts was completely removed. The width of the OD stabilizing band was reduced to limit the contact area, and the rough carbide was removed from all sides and replaced with smooth-ground crushed carbide on the pads to reduce torque and ease the dressing process. Due to the removal of the crushed carbide at the bottom, the clearance angle was also reduced as it was comparatively easier to achieve fine details on a machined surface compared to on one manually dressed.

The second mill machine test was successful in shaving off the desired material from an Inconel 925 sample, Figs. 16 and 17. The only constraint was the lower torque capability of the mill machine, which repeatedly tripped off with the heavy loads caused by the positive rake and tougher material.

The milling BHA for the second full-scale test consisted of a power swivel, three 12.49” nylon centralizers, crossover, 11” drill collar, crossover and mill suspended from an overhead crane — total BHA weight was 12,300 lbm, and it had a length of 39 ft. The centralized BHA was much larger, adding weight and stability to the mill. The other changes to the milling apparatus are listed here:

- A larger fluid supply tank was added, as well as a larger open-top mill tank, and a triplex pump was used to supply fluid at a 7 BPM circulation rate, Figs. 18 and 18a.
- Bolts were placed in the body of the BPV to simulate the retaining lugs for the fishing neck to ensure that the 3.25” or 3.56” stops placed inside the mill blades would be sufficient to prevent milling of the fishing neck lugs, Fig. 19.

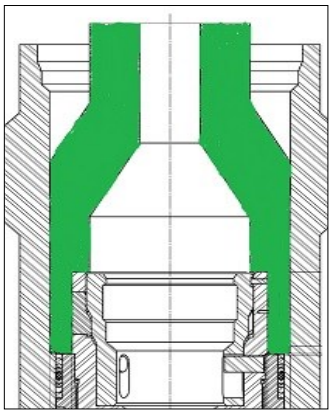

Fig. 15. Schematic of BPV area to be milled.

Fig. 16. Mill machine test 2.

Fig. 17. Inconel milled in test 2.

Fig. 18. Larger milling tank.

Fig. 18a. Larger full-scale tanks and pump.

- WOM capability was increased to 9,000 lbm with the use of an 11" drill collar.
- Nylon stabilizers were added to the top of the drill collar for stability inside the 16" OD riser.

Final Mill Test Observations

With these improvements incorporated into the milling apparatus, Fig. 20, and the use of two different types of mills for ID recess and BPV groove milling, the second test was conducted. The second test was successful in milling the desired sections of the tubing hanger and BPV, and it established suitable parameters for the actual job. Observations from the final test are given here:

- Octagonal inserts experienced minimal damage from anticipated milling loads and vibrations.
- The chip breaker profile was again unable to break the cuttings into smaller pieces, and the filings retrieved were still long strands of unbroken shavings.
- Separate mill designs for the tubing hanger ID recess and BPV significantly improved the milling efficiency.
- Better stabilization of the milling string and a more secure fixture aided in reducing vibrations and side loads, which increased the milling efficiency.
- The reduction in blades from nine to five reduced the work hardening, and therefore aided in faster removal of material from the BPV and tubing hanger.
- No impact was seen in the milling rate, with pump rates above 5 BPM, or with weights on the mill, which were above 5,500 lbm.

Fig. 19. Bolts inserted in the hanger and BPV fixture.

Fig. 20. Second full-scale test apparatus.

- The tubing hanger ID Mill1 successfully milled 3.473" with one mill in 7 hours and 51 minutes, using a light initial mill weight that increased from 1,000 lbm to 4,000 lbm WOM, with 35 rpm as the optimal speed and up to 1,500 ft-lb torque. The average mill rate for all mill runs was 0.482"/hour. A total of 5.493" was milled in 11 hours and 24 minutes, Fig. 21.
- The BPV Mill2 successfully milled 3.44" in 11 hours and 37 minutes, using three mills with 1,000 lbm to 5,000 lbm WOM at a speed from 36 rpm to 42 rpm. The average mill rate was 0.296"/hour for all mill runs, Fig. 22.

WELLHEAD TEST FREEZE THEORY AND PURPOSE

Several academic institutions and testing laboratories have performed significant research on cryogenic freezing as an isolation technique and have proven it to be an effective gas-tight barrier. It is used in other segments of the energy sector, such as refining and chemical plants, and it has proven to have no permanent effect on the common metallurgy used in oil field piping. Direct contact with N_2 induces a much greater temperature reduction in the material than using freeze water and brines. However, use of a jacketed type cryogenic freeze, which uses direct N_2 impingement, was not suitable for this application because no jacket had ever been made larger than 36" OD, and the odd shape of the wellhead made this impractical. A lower contact temperature was also preferred to minimize the potential detrimental effect on the electric resistance welded pipe in the lower wellhead.

The helical coil method is ideal for this type of application because it consists of the stainless steel flexible tubing that is used to transfer liquid N_2. This method prevents direct N_2 contact with the material, provides lower contact temperatures, and allows the rate of ice plug growth to be controlled more effectively, i.e., by regulating N_2 flow, removing insulation and applying a water spray.

A helical coil test freeze at a Houston, TX, facility was proposed to determine if a 26" to 41" steel mass with an inner 9⅝" tubing could be frozen to isolate a production tree from the wellbore, thereby providing a pressure-resistant barrier while the existing tree was removed and replaced by a BOP, which would then be tested, to prepare for a milling operation. Before this test, a technique had not been established for using helical tubing wrapped around a pipe with a diameter this large.

The purpose of the test was to determine if using the helical tubing method would generate enough temperature reduction over a 40" length of pipe to freeze fluid and keep it cold enough to provide an ice barrier capable of holding 10,000 psi pressure inside a 9⅝" pipe. The potential N_2 consumption and general characteristics of maintaining the freeze would also be determined.

DESCRIPTION AND APPLICATION OF EQUIPMENT PROCESS

The test stand, Fig. 23, was constructed to simulate the OD dimension and void area to be frozen in the field. The test stand consisted of a 12 ft length of outer pipe having a 26" OD and a welded section of 9⅝" OD pipe inside, all of which has been pressure tested to 10,000 psi. The coils would cover a length on the pipe comparable to the actual wellhead section length, Fig. 24. There was no previous case history of using the helical tubing method for a freeze of this size, so a ¾" tubing size and a double wrap of 500 ft of tubing was used to cover a 40" vertical length of the 26" OD pipe. The tubing was installed with 100 ft of 2" transfer hose to simulate the distance between the N_2 tanks and the actual wellhead in the field.

The precooling of the helical tubing started at a 10 psi N_2 tank pressure to determine the pressure required to push liquid N_2 to the end of the transfer hose and tubing — a combined length of 600 ft. Adjustments were made until frost appeared toward the end of the hose. It was determined that a pressure of 40 psi was required at the tank. The relief valves on the N_2 tanks came preset at 45 psi, and this test was conducted on level ground. The field situation required the N_2 tanks to be at a

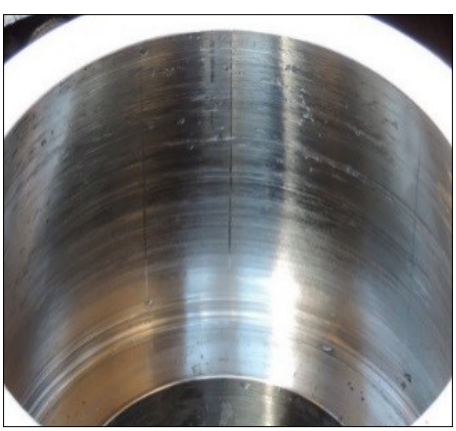

Fig. 21. Hanger recess fixture after milling.

Fig. 22. BPV fixture after milling.

Fig. 23. Freeze test stand.

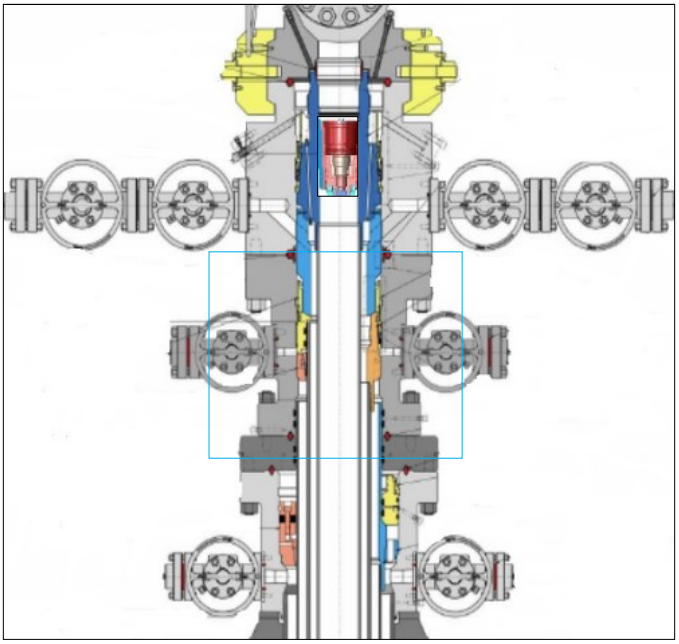

Fig. 24. Wellhead area to be wrapped with coil.

higher elevation, so no problem was expected for the N_2 supply pressure.

PRESENTATION OF FREEZE DATA AND RESULTS

Figure 25 shows the early stages of the coil cooling of the 26" OD mass over a 40" length. After 9 hours of saturating the coils with water, a 2" waterproof insulation jacket was wrapped around the ice covered coils to retain the cooling of the coils and force the cold inward to the 9⅝" tubing, Fig. 26. The lower external temperature probe under the coils was -4 °F, and the top temperature probe on the 9⅝" tubing measured 78 °F with an ambient temperature of 96 °F.

The ice plug was confirmed on the 26" annulus after 16 hours by bleeding off the pressure above the coils from 1,000 psi to 250 psi, while below the coils the 26" casing pressure remained at 750 psi. A pressure buildup on both the 26" casing and the 9⅝" tubing was expected during the freeze due to the limited volumes, so the pressure was bled down numerous times during the freeze to stay below the burst rating of the 26" casing. The freeze continued for a total of 26 hours to ensure the ice plug was sufficiently developed before beginning the pressure testing of the 9⅝" tubing and the 26" by 9⅝" annulus. The 9⅝" tubing pressure built to 3,200 psi due to ice plug expansion at the point the pressure tests were to begin.

The initial freeze test in Houston, TX, took place in late October with ambient temperatures of 55 °F to 80 °F. The 26" by 9⅝" annulus was pressured from the bottom of the stand against the ice plug up to 1,000 psi. The pressure was held with no anomalies for 30 minutes. A progressive pressure test of the 9⅝" tubing began at 1,000 psi and was increased in 1,000 psi increments to a maximum test pressure of 10,000 psi, which was held for 1 hour.

Fig. 25. Early stage of freeze.

Fig. 26. Added insulation.

A second freeze test was performed in August with ambient temperatures of 83 °F to 96 °F in more humid conditions to better replicate the weather in Saudi Arabia. In the second test, the 9⅝" tubing was tested to 10,000 psi for 4 hours with 1,100 psi in the 26" by 9⅝" annulus and an additional 4 hours with 2,000 psi in the 26" by 9⅝" annulus for a combined total of 8 hours. The ice plug temperature ranged from -50 °F to -154 °F during the 10,000 psi pressure test, and the total ice plug growth was 82". After testing, we vented all pressure from the test stand and stopped the N_2 supply.

The test conclusively proved that a helical coil N_2 freeze plug could be placed in higher ambient temperatures, but N_2 consumption was increased, as was the time required. Placement of the N_2 tanks is important to supply sufficient N_2 volume, and the pressure relief valves on the tanks need to be set at 45 psi or higher. The expected freeze time of 30 hours to 36 hours was based on an outside temperature of 85 °F to 90 °F and is a time relevant to freezing the 26" OD. The larger actual mass of the wellhead, ambient temperature, and wind conditions would extend the N_2 required and the total freeze time.

ACTUAL ON-SITE JOB RESULTS

To avoid the extreme heat of the Saudi Arabian summer, the freeze and milling operations were delayed until the fall, awaiting cooler daylight ambient temperatures of less than 90 °F. Notification was given for mobilization, and all support companies acquired and staged the materials needed for the project. The 14" × 9⅝" tubing casing annulus (TCA) was bled from 230 psi to zero and pressure tested to 500 psi. The TCA was flushed with freshwater and wellbore cleanup flushes to remove any oil or grease. The BPV was latched with the BPV pulling tool and an equalizing prong to ensure that there was no pressure trapped below the BPV and that the downhole ceramic disc was not leaking. The 9⅝" tubing was then pressured to 500 psi and fluid was bled back to ensure the BPV cove was open. The tubing retrievable subsurface safety valve (TRSSSV) was then closed before beginning the freeze operations.

The personnel for a continuous 24-hour/day operation were dispatched offshore to begin the process of staging the N_2 tanks and arranging the logistical support. Additional tanks were held in the staging area to be delivered as required. The wellhead area was isolated with tarpaulins to limit the exposure to wind, which can have an effect on the N_2 use and freeze time, Fig. 27. The 600 ft of ¾" helical tubing was wrapped around the "B" section, covering 43" of the casing spool for 26" to 41" OD, Fig. 28, and temperature probes were placed on the exterior of the wellhead. A 2" supply hose was run from the N_2 tanks on the cantilever deck to the wellhead. The freeze was directed at the B section of the wellhead to prevent freezing the 18⅝" electric resistance welded pipe that was landed in the starting head. This was controlled during the freeze by running water over the starting head.

Liquid N_2 was gravity fed to the wellhead through the supply line and tubing at a 35 psi tank pressure to pre-cool the lines, which took approximately 12 hours. Water was sprayed onto the ¾" tubing until the ice formed; the ice was 5" to 6" thick after 21 hours. Egg-crate insulation and tarps were then wrapped around the ice mass to help "push" the cold toward the ID of the casing spool, Fig. 29.

Fig. 27. Wellhead with tarps installed.

Fig. 28. Installation of coil.

The initial pressure test failed at 1,000 psi 26 hours after beginning the freeze. The external temperatures across the wellhead freeze area were -62 °F to -151 °F at this time. The determination of a successful test was based on the volume pumped vs. pressure from the wellhead history, and on calculations for water compressibility due to the ice plug vs. that of the entire tubing volume. This was critical since the only barrier remaining in the well was a 15,000 psi rated double glass disc. Any pressure that escaped below the ice plug would go through the closed TRSSSV and be exerted on the glass disc. A substantial portion of this pressure would be trapped below the TRSSSV. The TCA pressure was also monitored and increased during the failed test. Subsequent pressure tests were conducted after 33 hours to 1,950 psi and after 45 hours to 2,470 psi, but both failed while maintaining external temperatures of -74 °F to -125 °F, respectively. The TCA was flushed again with freshwater and surfactants.

Fig. 29. Wellhead with insulation installed.

The possible reasons considered for the pressure test failure were grease or other oil lubricants in the freeze area, ice compaction and a lower weight calcium bromide solution than the expected 13.5 ppg fluid — the true crystallization temperature (TCT) point becomes colder as the fluid weight decreases from 13.5 ppg to 11.8 ppg with the maximum difference at 12.8 ppg with a TCT of -96 °F vs. -39 °F for a 13.5 ppg fluid[1]. On the basis of these uncertainties, it was decided to add 200 ft of coil to the Unihead and extend the freeze area up an additional 20", Fig. 30. The N_2 feed line was spliced to divert flow into all three coils surrounding the wellhead. Additionally, the time needed to freeze was doubled to allow the cold to penetrate through the 9⅝" tubing.

The placement of coil this high on the wellhead was initially avoided to prevent ice from forming around the terminating flange for the TRSSSV control line and on the speed-lok for the Unihead, as the ice freeze line grows up and down vertically with time. Water spray was used to control the growth of the freeze line. The next pressure test was conducted 42 hours after adding the additional coil, and 4 days after the initial freeze initiation. The pressure test failed at 3,000 psi because of a line leak, but the ice plug appeared to be in place, based on the volume pumped. The pressure stabilized at 1,600 psi and was held there to aid in pre-compacting the ice plug, which was believed

Fig. 30. Adding additional coil.

to be occurring during the pressure test, resulting in a failed test. The final successful pressure test was conducted 5 days after the initiation of the freeze, and the pressure held for 1 hour at 3,000 psi and 3 hours at 10,000 psi. The temperatures across the wellhead ranged from -135 °F to -188 °F. The N_2 feed rate was averaging 107 gallons per hour during this time. The ambient temperature fluctuations from daylight to night resulted in the external temperature on the wellhead varying from -100 °F to -180 °F from day to night, respectively.

After all parties agreed the safety issues were satisfactorily addressed, the 9" tree and lower master valve were removed. Upon nipple down of the tree, the TRSSSV control line was cut just above the tubing hanger and plugged, and the BPV was inspected. Upon this inspection, the fishing neck was found to be protruding ⅞" above the top of the BPV body, and grease was found packed in the ice slush above the BPV. The two BPV mill stops prepared for the job were initially set at 3.25" and 3.56" to prevent milling through the retaining lugs for the BPV fishing neck at 3.65". The fishing neck extending upward ⅞" required that both these mill stops be increased by equal measure to enable the intended swallow of the BPV. Detailed measurements were taken from the rotary to the top of the BPV, fishing neck and tubing hanger to be used as the reference for milling.

A double 18¾" 15,000 psi BOP was installed on top of the 18¾" Unihead with inverted blind shear rams, along with a quad 18¾" 15,000 psi BOP (with 9⅝" pipe rams), a 10,000 psi annular, a riser and a big bore diverter. The bottom double inverted rams would be used to conduct the pressure test on the primary well control BOP stack, as well as any additional BOP tests required during the course of the operation. This was necessary because the normal BOP test plug could not be set in the wellhead owing to the stuck BPV. The initial BOP body pressure test against the ice plug to 300 psi and 10,000 psi was successfully conducted after 2 days and 6 hours of the ice plug placement. The ice plug was held in place a total of 4 days and 20 hours while the BOP was installed and fully pressure tested. Approximately 2,000 gallons of N_2 was used per day to hold the freeze, and the total N_2 consumption from the beginning of the freeze to the end was 22,000 gallons.

After the BOP's efficacy was confirmed, the thawing process began by disconnecting the additional third coil and leaving the initial two coils supplied with N_2 for the next 24 hours while spraying the wellhead with water to control the thawing process. The N_2 supply was then removed, and the wellhead temperatures remained above freezing after a total of 38 hours. The wellhead temperatures were all above 60 °F after 46 hours with the speed-lok adapter at the top of the Unihead at 80 °F.

Once the thawing process was completed, a second run was made with the BPV pulling tool to ensure no pressure had been trapped below the BPV due to the freeze. At this point an unsuccessful attempt was made to release the anchor seal assembly using a modified tubing hanger retrieving tool. The 9⅝" anchor latch had to be rotated 13 turns to release the anchor so the tubing hanger could be pulled with the stuck BPV in place

without milling.

The BOP stack was flushed with filtered freshwater and wellbore cleanup surfactants before a 360° real-time circulating-type color camera was run on the milling BHA to inspect the BPV. During the course of many runs with the camera, it was found that seawater from the deep well sump provided better pictures than filtered freshwater. The milling distance was determined by a fixed plumb line string across the drillstring on the rig floor and a 1/32" scaled ruler.

The initial tubing hanger ID recess mill — Mill1 — was run below a float sub, two 15 ft 9⅝" OD drill collars and two short 9½" OD drill collars, a 22¾" OD nonrotating stabilizer, a short 9⅝" OD drill collar and a crossover to the top drive. Mill1 successfully cut the ID recess downward 2½" to the top of the BPV in 2 hours with two mills while pumping seawater at five BPM using 2,000 lbm to 3,000 lbm WOM, and 40 rpm, with 1,600 ft-lb to 2,300 ft-lb torque.

The initial BPV Mill2 run was made with the same BHA as Mill1, but the mill could not enter the tubing hanger because the blades caught the lip of the tubing hanger. Therefore, the 22¾" OD nonrotating stabilizer was removed, which was not planned, but this enabled the Mill2 to enter the top of the tubing hanger. The combination of BPV and tubing hanger body was milled on four successive mill runs over 2¼", reaching ½" from the bottom of the locking keys before the milling progress stopped. The milling was performed with 1,000 lbm to 7,000 lbm WOM, 35 rpm to 40 rpm, and up to 3,500 ft-lb torque. The camera runs showed the mill to be slightly off vertical, and the mill wear pattern indicated it was becoming wedged because of its long OD gauge as it milled down over the BPV. Additionally, the potential movement of the retaining lugs may have been interfering with the mill's progress — mill cutting requires the surface milled to be solid because milling relies on a stable milling surface.

Given the lack of progress, it was decided to make an attempt to pull the BPV. A drillpipe conveyed, GS flow release tool was run and pulled 65,000 lbm on the BPV, but the BPV could not be pulled free. This was the expected outcome since the remaining 1¼" of material was still wedged against the BPV. The pre-job mill test had proved the mill capable of milling the BPV when it was stable and properly aligned with the milling surface, so our initial plan to use stabilization for alignment was re-visited.

The alignment of the rig over the wellhead was critical to the milling operation, and efforts were made to ensure the alignment of the rotary was centered with plumb lines. Despite this effort, the top drive was still not centered through the rotary. This made it impossible to enter the top of the tubing hanger with the bladed arms of the mill with the full OD riser stabilizer in place.

It was decided to attempt to re-center the milled surface by re-installing the stabilizer and re-running Mill1 and Mill2 from the top down to remove any material that was not vertically aligned, and therefore could be wedging against Mill2. It was determined that the only means of entering the tubing hanger with the bladed mill was to soft close the pipe rams to align the mill over the center of the tubing hanger.

The camera was run continually through the milling process to capture pictures, Fig. 31, which provided invaluable information on the milling progress and monitoring of the removal of the very thin foil-like cuttings. In Fig. 31, the milled smooth tubing hanger ID can be seen, along with the outside of the BPV, which has been removed.

The combination of tubing hanger ID and BPV was milled slowly again down to the previous milling point using the full OD stabilizer. The next two mills made ⅝" progress over 15 hours, and then progress stopped for the next 10½ hours on the next two runs. This was believed to be caused by the retaining lugs being freer to move and possibly wedging against the mill. The milling parameters were changed from the mill test, replacing the test parameters with slower rpms (in the range of 20 rpm to 30 rpm) and lighter WOM (2,000 lbm to 5,000 lbm). These changes enabled the milling to continue 3.48" over the BPV. The surface measurements were also confirmed by brass inlaid tags placed on the ID of the last two mills as we approached the lug. The 3.56" mill stop would prevent the lug from being milled only if the fishing neck was still in the up position, so the brass tail provided an actual milled mark inside the mill for reference.

The second attempt to pull the milled BPV, Fig. 32, was successful, with 27,000 lbm overpull applied using the GS flow release pulling tool on a 4" drillpipe. The fish neck was found in the up position (⅞"), and milling stopped 3/16" above the retaining lugs for the fish neck as expected. A total of 15 mill runs were made, which was far greater than the four used in the second trial test.

Figure 33 shows a fully operational BPV where the locking keys can clearly be seen with the fishing neck in its proper position. By comparison, Fig. 32 shows the milled keys and milled BPV body, and the fishing neck in the up position.

The 9⅝" tubing anchor seal assembly was subsequently re-

Fig. 31. Picture of actual milled BPV.

Fig. 32. Actual recovered milled BPV.

Fig. 33. New BPV.

leased successfully using a left-hand release spear, both a first in the industry.

CONCLUSIONS

Milling Test

1. Inconel is a difficult material to mill in downhole conditions, but with proper planning and a suitable design, it can be successfully performed.
2. Scaled tests to obtain a suitable cutting matrix are a cheap alternative to full-scale testing, but these should not be used to validate the design and parameters for complex downhole milling jobs.
3. In high cost wells, it is important to test the well intervention off-site to determine suitable parameters and equipment design.
4. Any moving pieces to be milled should be included in the test fixture. The BPV keys created difficulty during the actual milling.

Freeze Test

1. An ice plug rated to 10,000 psi can be successfully placed across a 26" OD mass with an inner 9⅝" tubing.
2. All the potential fluid types to be frozen should be included in the pre-job test to determine the freeze temperature and time.

Actual Job Conclusions and Lessons Learned

1. An ice plug can be successfully placed across a large OD mass — 26" OD with an inner 9⅝" tubing — and pressure tested to 10,000 psi; it can be held for multiple days to act as a well control barrier.
2. The ice plug freeze is sensitive to contaminated materials, such as pipe dope, grease, oil or varying chloride content. All voids to be frozen should be displaced with water when conditions allow. In this case, it was not possible to displace the tubing with water in the closed system, and there was concern for the ceramic disc integrity.
3. Relief valves set at 45 psi or higher should be used in the field. If this is not possible, the distance from the freeze point and the N_2 supply tanks should be shortened. Partially filled N_2 tanks had a significant impact on the feed rate of N_2 to the coils.
4. The mass of the wellhead and unknown contaminants in the wellhead freeze area extended the freeze time and resulted in the need for an additional coil over a larger placement area.
5. The holding pressure on the ice plug after freeze initiation can lessen the effect of ice plug compaction and lead to failed pressure tests in larger tubing. The compaction can result in a failed pressure test with small test volume changes affecting the recorded pressures.
6. Establishing pressure vs. volume changes expected during the ice plug test is necessary to analyzing a successful test, i.e., limiting pressure to above the ice plug or pressuring the entire volume below the ice plug.
7. Conducting the ice plug freeze when the ambient temperature was lower aided in the placement of this large mass ice freeze.
8. Predictive freeze modeling was not available at the time of the freeze to predict freeze time and N_2 consumption. Recent improvements in the finite element analysis modeling in use for predictive freeze modeling that is based on actual freeze conditions, supported by case histories, should be used going forward.

9. The recovered BPV in appearance was just like the BPVs milled in the trial test runs, proving the pre-job mill test design work invaluable.
10. Any deviations on the actual job from pre-job parameters used as the basis for design should be scrutinized unless there is no on-site solution to prevent the deviation, such as that encountered with the removal of the riser stabilizers.
11. Alignment of the rotary and top drive over the wellhead in this type of milling operation is critical to its success.
12. Without the use of the drillpipe conveyed, 360° view and circulating-type camera, the milling operation would not have succeeded.
13. The addition of the brass internal tags on the Mill2 blade ID was a valuable on-site adaptation to confirm the measurement of the milling progress to within 1/16".
14. The pre-job milling lathe and full-scale apparatus test provided confidence that the mill design was correct for milling the material and provided the milling parameters to be used as a basis for success.

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He is a patent holder and master of freezing techniques who continues to expand industry knowledge, increasing the effectiveness of intervention operations around the world.

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Application of X-ray Powder Diffraction and Rietveld Phase Analysis to Support Investigations of Failure for Submersible Pumps

Dr. Husin Sitepu and Dr. Syed R. Zaidi

ABSTRACT

This article illustrates the applications of advanced X-ray powder diffraction (XRD) and the Rietveld phase analysis in the oil industry. XRD, which can be used to determine the polymorphs and crystalline phases of actual compounds present in the sample, is an excellent tool to identify the solids, sludge and deposits accumulated or formed at different locations within electrical submersible pumps (ESPs). Rietveld phase analysis has the advantage over conventional reference intensity ratio methods, given that no standards are required to achieve accurate results to within ±1%. The phase compositions obtained from Rietveld phase analysis of XRD data of the sludge and deposits can guide the engineers and scientists at the refinery and gas plant to overcome the deposition problems by drawing the right procedures.

From the Backyard Dune to Fracturing a Highly Tectonically Complex Formation in Saudi Arabia

Kirk M. Bartko, Ibrahim H. Arnaout, Khalid S. Al-Asiri, Kenneth M. McClelland, Nayef I. Al Mulhim, Roberto Tineo, Dr. M. Nihat Gurmen, Ziad Al-Jalal, Dr. Danil Pantsurkin and Denis Y. Emelyanov

ABSTRACT

Sand in Saudi Arabia is easily accessible through surface mining or excavating large dunes that are API approved, but like many sands around the world, it lacks the necessary strength for fracturing high stress formations. To exploit the sand, a novel engineered workflow, enabled by the flow channel fracturing technique, was established for qualifying and implementing Saudi Arabian sand for use in fracturing to stimulate the tectonically complex, ultra-tight "T" carbonate formation.

Impacts of EOR Chemicals on Calcium Carbonate Scale Formation and Inhibition

Dr. Qiwei Wang, Dr. Waleed N. Al-Nasser, Faez H. Al-Dawood, Tawfiq A. Al-Shafai, Dr. Hameed Al-Badairy, Dr. Shouwen Shen, Hassan A. Al-Ajwad and Dr. Feng Liang

ABSTRACT

A field trial has been planned for a chemically enhanced oil recovery (EOR) project in Saudi Arabia. The injection chemicals will be a combination of surfactants and polymers. There is a concern that the breakthrough of these chemicals in produced water could affect scale formation process and so interfere with the scale treatment program. The objective of this study is to investigate the potential impacts of the injected EOR chemicals on calcium carbonate ($CaCO_3$) scale inhibitor performance.