Critical Factors Affecting Pulsed Neutron Saturation Monitoring in Carbonate Reservoirs

Yahia A. Eltaher, Dr. Shouxiang M. Ma, and Mamdouh N. Al-Nasser

ABSTRACT

Pulsed neutron (PN) spectral carbon-oxygen (C/O) logging is a widely used shallow measurement for time-lapse reservoir saturation monitoring. Because of its shallow depth of investigation, its measurement is affected by several factors, among which the near wellbore logging environment is the most important. For example, hole condition, cement quality, and fluids in the wellbore have drastic effects on C/O measurement. Some of these effects, such as those due to oil holdup in the wellbore, can be corrected for in the data post-processing. Others might have a permanent imprint on the data, which cannot be removed. It is therefore extremely important to fully understand the effects of the different physical parameters within the wellbore vicinity that might be affecting the measurements.

An extensive study was conducted in a field where reservoir saturation monitoring logs encountered discrepancies in water saturation between open hole and C/O logs, where the latter showed changes in saturation not supported by production history. It was found that one of the main reasons behind this discrepancy is the effect of mud filtrate invasion on the shallow C/O measurement, which varies as a function of time and rock-type characteristics. Other factors, such as the wellbore fluid reinvasion effect across zones of perforation, also play a role.

In this article, the effect of mud filtrate on C/O logs is demonstrated with field examples and criteria used to diagnose this phenomenon is defined. Other factors affecting C/O measurement such as wellbore fluid reinvasion and cement condition, are also highlighted. Finally, we present recommendations and best practices to conduct a more representative monitoring of reservoir saturation.

INTRODUCTION

Reservoir surveillance and time-lapse saturation monitoring are the primary techniques used to gather reservoir dynamic data for optimized reservoir management and making reservoir engineering decisions[1]. There are many techniques of saturation monitoring that are being routinely used in the industry, ranging from slim open hole resistivity[2], slim cased hole resistivity[3], and pulsed neutron (PN) spectral carbon-oxygen (C/O) and thermal capture sigma (Σ) logging[4, 5]. Recently, reservoir scale electromagnetic surveys have also been field tested successfully; among vertical wells[6], horizontal wells[7] and from borehole to surface[8].

Each of the abovementioned techniques has its own advantages and disadvantages, and use of a specific technique for reservoir saturation monitoring is a fit-for-purpose choice depending on factors such as job objectives, tool applications and limitations, borehole and near wellbore conditions, as well as reservoir characteristics[9]. Among all these techniques currently available in the industry, PN logging is still the most practical, and therefore, popular, as explained next.

For common applications, PN logging tools provide basically two types of measurements, each is acquired under a specific set of logging procedures and for certain applications. In-elastic spectral C/O measurement is mainly applicable in cases where the formation water salinity is fresh or unknown, due to mixing between injected and connate water, while Σ logging is used in cases where the formation water salinity is known to be high. Other applications exist such as gamma ray (GR) spectroscopy for lithology determination, PN porosity measurements[10], gas saturation quantification[11], formation water salinity[12], and activation logging; which can be acquired for water velocity determination — oxygen activation — or gravel pack evaluation — silicon activation.

Being a nuclear tool, PN logging is statistical, and therefore results can be uncertain, and its depths of investigation (DOI) are relatively shallow[13, 14]. Consequently, there are many factors that can have significant effects on its measurements and applications, as summarized in Table 1, updated after[15] and classified into the following categories:

1. Nature of the measurement, i.e., statistical, and has a shallow DOI.
2. Tool capabilities, e.g., detector type, etc., and spectral data processing — windows or yields.
3. Formation properties, i.e., porosity and lithology.
4. Wellbore properties, such as:
   a. Completion type — cased hole or open hole.
   b. Hole size and condition, casing size, wellbore fluids, etc.
   c. Cement quality.
   d. Well condition — flowing or shut-in.

5. Relevance of the interpretation model.

6. Systematic errors, which can be grouped into the below factors:

    a. Tool condition: Performance during the job; in terms of generator steadiness, detector efficiency, etc.

    b. Acquisition procedures, such as:

    - Number of logging passes.
    - Depth control among individual passes.
    - Steadiness of logging speed and count rates among passes.
    - Tool positioning.
    - Sticking and dragging.
    - Gain stabilization — mainly for temperature sensitive detectors.

    c. Data processing and interpretation technique, such as:

    - Depth control to open hole data.
    - Data processing parameters, such as oil carbon density[16].
    - Environmental corrections, most importantly is the accurate oil holdup (Yo) calculation.

From Table 1, it is seen that there are several factors related to the borehole and near wellbore conditions that are important in affecting PN log quality and results. As C/O measurements are shallower than Σ; the C/O log quality may be affected more by those factors. These wellbore and near wellbore effects belong to the following two main categories:

1. Permanent effects on PN measurements that would be very difficult to be compensated for; such as borehole rugosity and cement quality[17-19].

2. Temporary effects, such as drilling mud filtrate invasion[20] and wellbore fluid reinvasion[21].

In this article, we will investigate some of these factors in detail and evaluate their significance in terms of impacting PN logging and log data quality for better and more conclusive assessments of reservoir dynamics.

PN LOGGING

Most PN logging tools are based on neutron GR interactions, though neutron-neutron tools are also commercially available. The physics of the neutron GR tool is based on the detection of GRs and their energies vs. time.

These GRs result from inelastic interactions, for C/O logging, between high-energy neutrons and elements within the measurement region, including wellbore and near wellbore. The detected GRs with characteristics related to the specific materials

Factors	Σ	C/O	Remarks
DOI (in)	12	6	Commonly quoted
Vertical resolution (ft)	2	2	Commonly quoted
Lower Φ limit (pu)	10*	12-15	Commonly quoted. *Representative Sigma measurement is a mutual function of both formation water salinity and porosity.
Poor detector efficiency			Will significantly impact the photo-peak efficiency, degrade the resolution of the spectra and will be difficult to extract good data quality.
Low generator efficiency			Even at a lower count rate, an acceptable measurement is possible if a good detector is being used.
No. of casing strings	2	1	Maximum
Hole rugosity of 2”			
Poor cement quality			
Borehole fluid invasion/ reinvasion			
Borehole fluid holdup			Inaccurate
Acid stimulation			Cl will directly impact Sigma log. Also, might alter original porosity mainly in carbonate reservoirs, and thereby affect C/O interpretation.
Freshwater			Such as < 20 ppk
Mixed salinity			OK, if salinity is known.
Oil carbon density			Nonrepresentative
Low S_w			Higher uncertainty
Well stability			Well instability during logging will affect borehole fluid contacts, and therefore, data processing and interpretation

Notes on color codes: Red – Warning, technique may not apply; Yellow – Use with caution; and Green – Recommended.

Table 1. Sigma and C/O logging and factors affecting their measurements

	NaI	GSO	BGO	GYSO	LaBr3	YAP
p (g/cc)	3.67	6.71	7.13	6.29	5.08	5.37
Z	51	59	75	67	47	31.4
ER (%)	7.0	8.0	9.3	12	2.9	4.38
LO (%)	100	18	12	20	165	40
TC (%/°C)	-0.3	-0.3	-1.5	-0.3	-0.05	0.39

Table 2. GR detectors used in PN logging tools — crystal types and their properties

encountered by the fast neutron cloud. Therefore, the measurement is used in quantifying carbon (indicating hydrocarbon), oxygen (indicating water), and calcium and silicon for lithology.

Further collisions of neutrons with the surrounding environment lead to its energy reduction and eventual capture by a target nucleus. This capture causes a temporary excited state in the capturing nucleus. Return of the nucleus to its original condition releases a GR with characteristics of the capturing element. This characteristics within the energy spectrum allows identification of the capturing element in Σ logging.

Therefore, Σ logging has a relative deeper DOI compared to C/O logging, where the latter is a statistical measurement and the precision of results depend primarily on:

- Output of the neutron source. Modern generators produce much higher output[10].
- Performance of the GR detectors, as summarized in Table 2 for most commonly used crystals, where in terms of crystal density (*p*) the higher the density the more powerful to stop GRs. Also, the higher the crystal effective atomic number (*Z*) the more effective to stop GRs. Energy resolution (ER) in % at 662 keV for a 1 cm cubed crystal; where the lower the better resolution of identifying elements. Light outputs (LO) in % and the higher light output of a crystal the better performance. Finally, temp coefficient (TC) in %/°C and the smaller the absolute value the more stable the performance.

Note that in commercial logging tools, the standard crystal length is kept at 6” while their diameters vary from 1.1” to 1.4”. Obviously, the larger the crystal volume, the more powerful to stop GRs. In addition, modern electronics for fast data acquisition and processing also help improve the performance of the neutron generator and GR detectors.

CRITICAL FACTORS AFFECTING PN LOGGING

Drilling Mud Filtrate Invasion

During drilling, drilling mud filtrate invades into the near wellbore formation. The amount of invaded filtrate and the depth of the invasion depend on how well the mud properties — such as solid particle size distribution — match the formation rock properties — such as pore throat size distribution — and the overbalance pressure applied during drilling.

For a conventional reservoir interval containing oil at

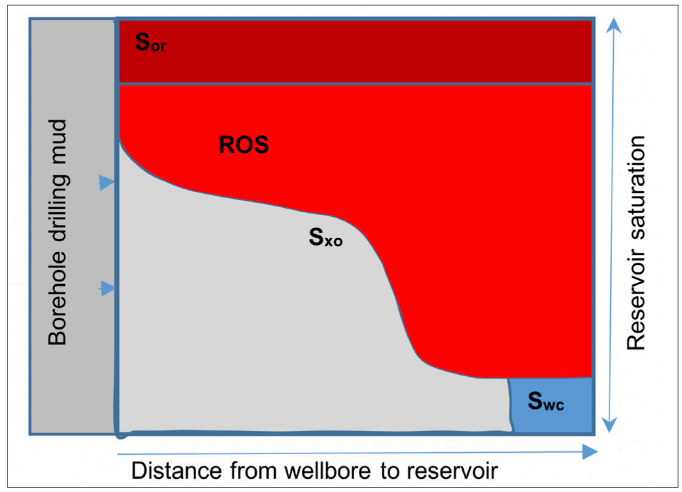

Fig. 1. Illustration of the effect of drilling mud filtrate invasion on near wellbore reservoir saturation.

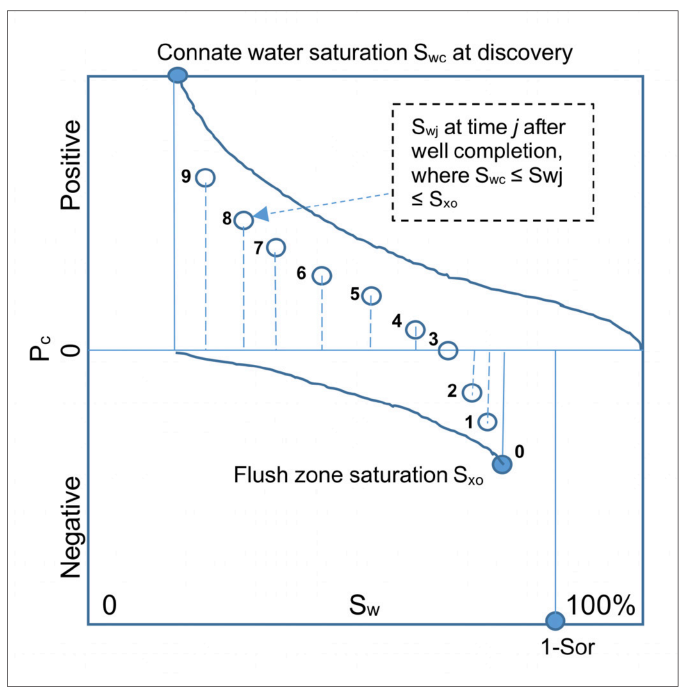

Fig. 2. Model used to explain changes in near wellbore reservoir saturation after drilling.

connate water saturation, S_{wc}, initial fluid distributions in the reservoir rock pore space were determined by a drainage process during original oil migration. Water-based mud filtrate invasion redistributes oil and water through forced imbibition with water saturation in the near wellbore region increasing from S_{wc} to flushed zone saturation, S_{xo}, Fig. 1.

The S_{xo} maximum may be close to 1-S_{or}, where S_{or} is the reservoir residual oil saturation. To link those saturations with fluid displacement processes, the relative locations of S_{wc}, S_{xo}, and S_{or} are drawn on a water saturation vs. capillary pressure map, Fig. 2.

Formation Evaluation with Open Hole Logs

From both Figs. 1 and 2, it is clear and well understood in open hole log formation evaluation that water saturation derived from shallow measurements such as micro-resistivity, nuclear magnetic resonance, dielectric, and C/O immediately after drilling is an S_{xo}; which is higher than reservoir S_{wc}. The shallower the measurements, the bigger the difference between S_{xo} and S_{wc}, i.e., the less representative of the target reservoir. Consequently, deep resistivity, which can read into the reservoir up to about 10 ft from the wellbore, was developed for formation evaluation.

Time-Lapse Reservoir Saturation Monitoring

From Fig. 2, it is noticed that S_{xo} is at its maximum during drilling, and it would be gradually reduced from S_{xo} at time zero toward S_{wc}, through a path of secondary drainage as shown from point 1 to 9. If a well is completed cased hole without proper cleanup and flow back, the process of restoring near wellbore reservoir saturation, S_{wj}, from S_{xo} toward its original state S_{wc} may take a long time, sometimes several years[20].

For wells completed open hole, the saturation restoration process should be faster. But it would still take time due to capillary hysteresis[22].

The rate of saturation restoration depend on rock and fluid properties, as well as the severity of the original drilling mud filtrate invasion. The driving forces for this saturation restoration process are due to:

- The initial viscous flow, due to the remaining pressure differential from overbalance drilling.
- The fluid diffusion resulting from the saturation profile, Fig. 1.

The example shown in Fig. 3 demonstrates the effect of drilling mud filtrate invasion, as evidenced by the separation of

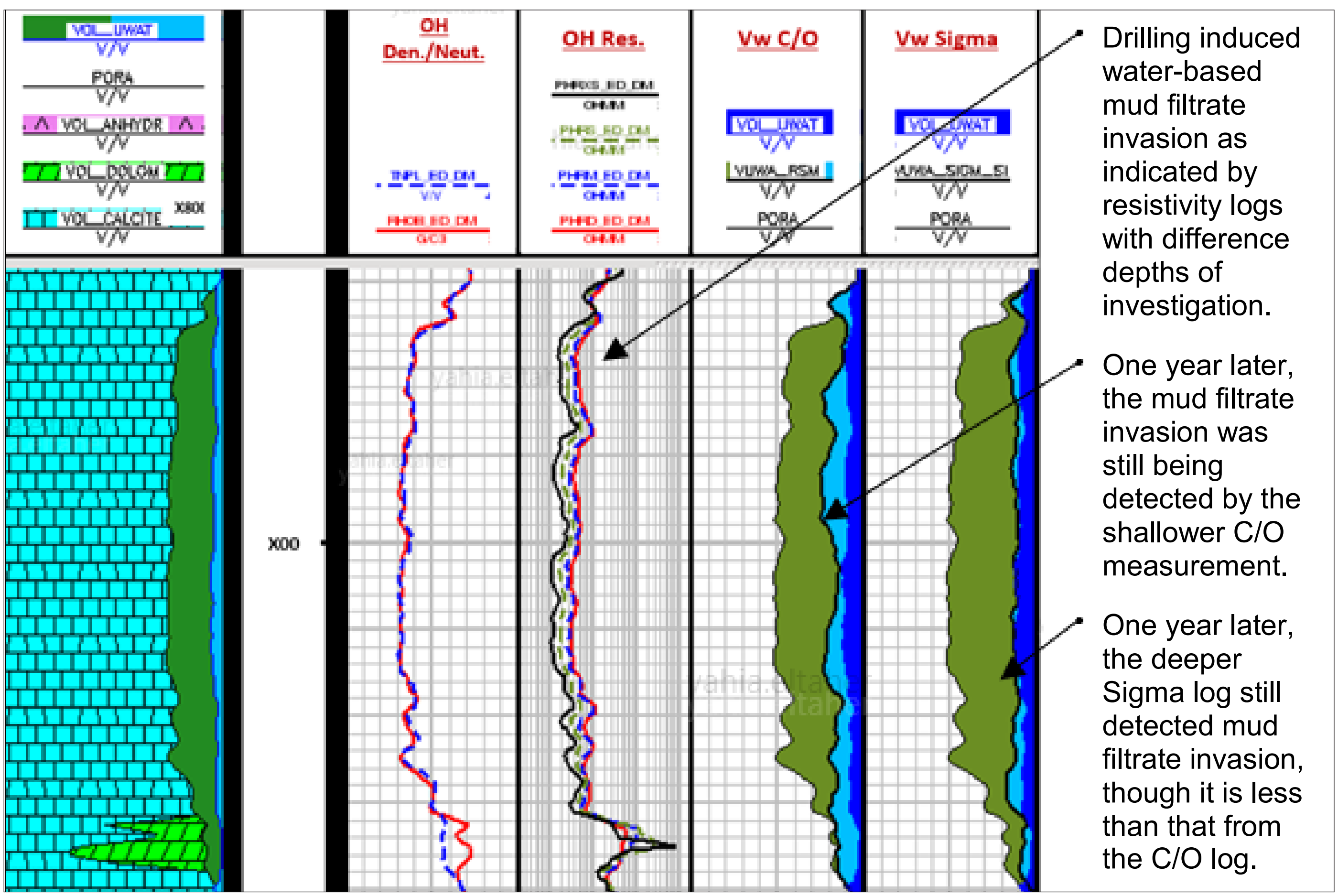

Fig. 3. An example of drilling mud filtrate invasion and its effect on time-lapse PN logging. Tracks 4 and 5 display C/O and Sigma log results (dark blue is water volume (Vw) derived from a deep open hole resistivity log, light blue is Vw from a PN log, and green is oil).

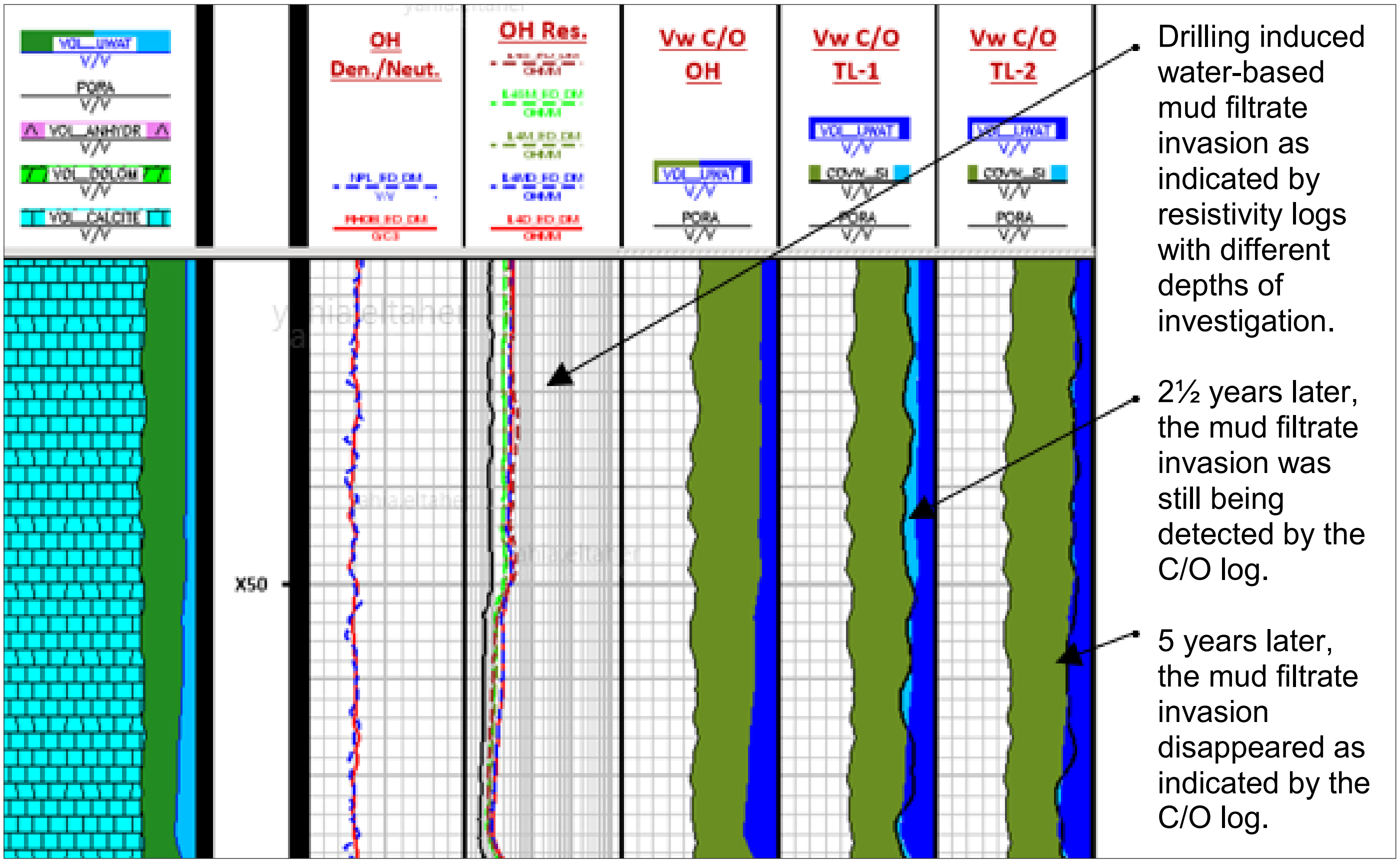

Fig. 4. An example illustrates dissipation of mud filtrate invasion in this observation well completed cased hole. Tracks 5 and 6 are time-lapse C/O logs run 2½ and 5 years after drilling, respectively.

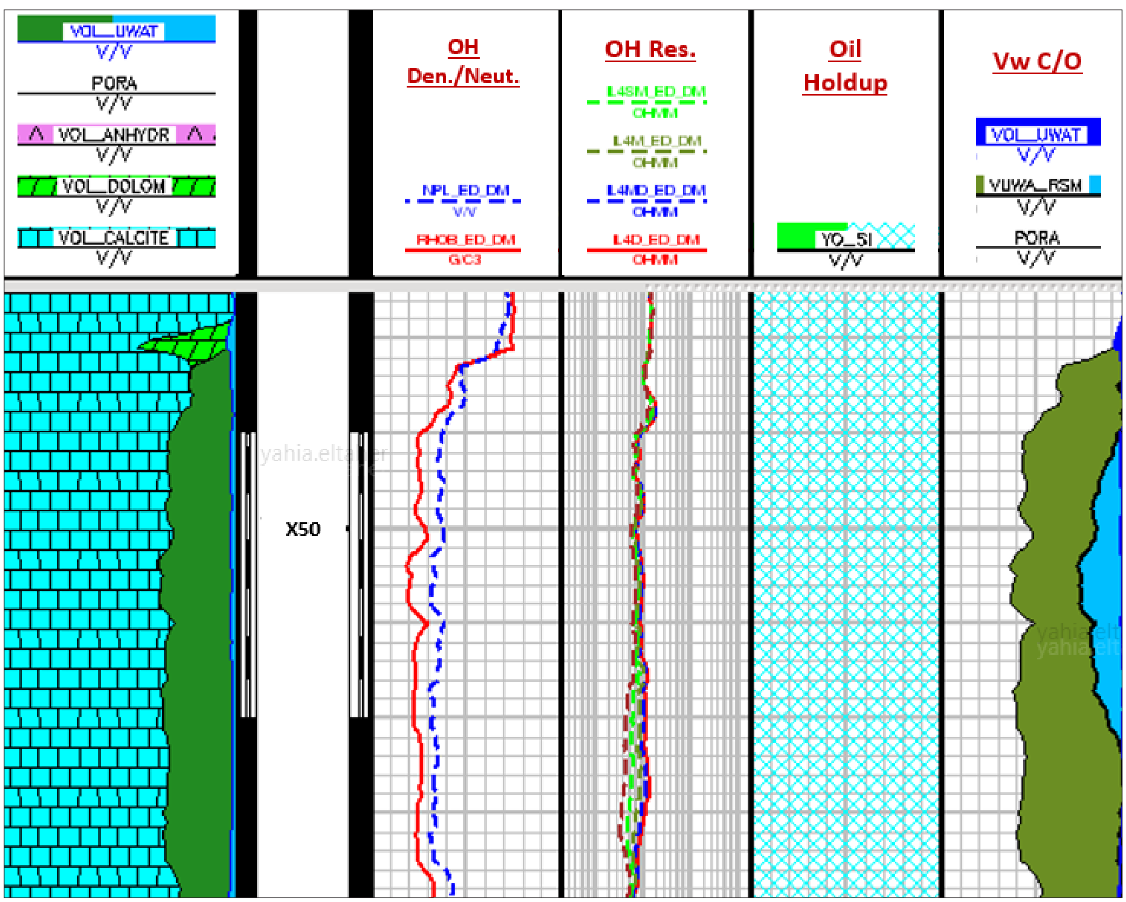

Fig. 5. An example of borehole fluid reinvasion. Track 4 is the borehole fluid holdup.

original open hole resistivity logs with different DOIs. One year after the well was cased hole completed, part of this invaded filtrate was still detectable by the shallow PN log, especially the shallower C/O log.

Dissipation of Mud Filtrate Invasion

Figure 4 shows an example of mud filtrate invasion as evidenced by the separation of original resistivity logs with different DOIs (Track 3). A C/O log run 2½ years after drilling indicates that the filtrate invasion still existed (Track 5), while the invasion disappeared from the second C/O log run 5 years after drilling (Track 6). It seems that dissipation of mud filtrate invasion would take more than 2½ years, consistent with other observations[20].

Bore Fluid Reinvasion

If a well is shut-in, or dead, due to insufficient reservoir energy, borehole fluid would reinvade back into the formation — through the open hole interval or perforations — whenever hydrostatic pressure in the borehole is greater than the near wellbore formation pressure. If borehole fluid reinvasion occurs, the S_{wj} will be altered and results of shallow DOI measurements will not be representative of the target reservoir. An example is shown in Fig. 5.

As shown by the open hole resistivity logs with different DOIs (Track 3 in Fig. 5), drilling mud filtrate invasion was not severe since all resistivity logs read essentially the same value, especially across the upper part of the interval where the casing was perforated, therefore, a communication channel was opened between the borehole and the reservoir. Results from a C/O log run 4½ years after drilling indicate high water saturation only across the perforation, due to water in the borehole reinvading back into the formation.

Workover Wells

Due to concerns of borehole fluid reinvasion back into the formation, if a well is scheduled to be worked over, a reservoir saturation monitoring log, if needed, should always be run before the well is killed for workover, not during or immediately after a workover job. A typical workover fluid is heavy brine, which can invade deep into the formation under normal workover pressure, making the reservoir saturation monitoring log reading nonrepresentative to reservoir saturation.

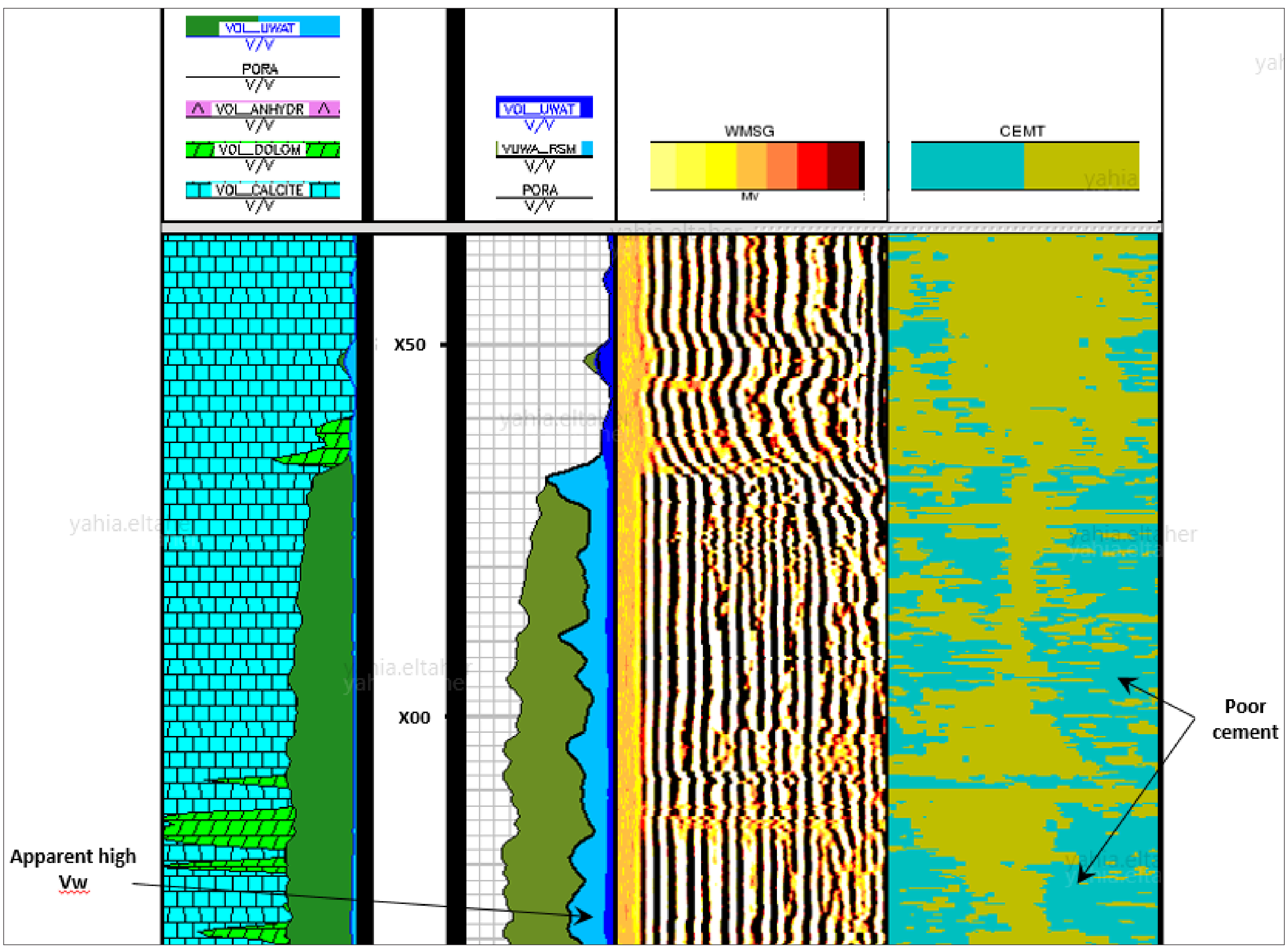

Fig. 6. Effect of poor cement quality on apparent water saturation calculated from C/O measurements.

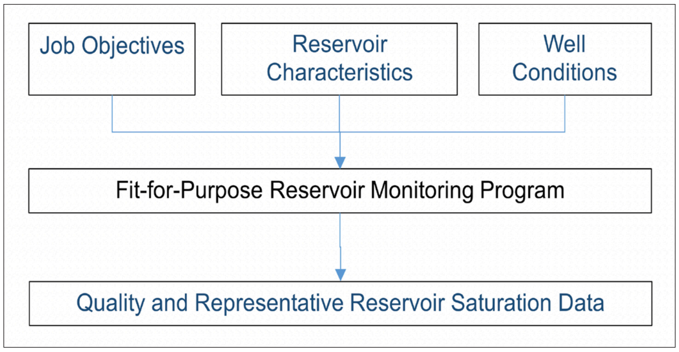

Fig. 7. Objective driven workflow to ensure quality and representative reservoir saturation monitoring data.

Poor Cement Quality

Cement quality is not only critically important in well control, but also has a direct effect on PN reservoir saturation monitoring[23]. With regard to the effect of cement quality on saturation monitoring using C/O logs, an example is shown in Fig. 6. In this case, across the intervals where the cement quality is poor, as shown by the cement bond log variable density log image (Track 3) and ultrasonic cement bond map (Track 4), an abnormally high water volume may be seen due to fluid channeling (Track 2).

BEST PRACTICES IN ENSURING QUALITY RESERVOIR SATURATION MONITORING

As previously discussed, many factors can affect the outcomes of a reservoir saturation monitoring job. These include:

- Tool limitations and applications — Tables 1 and 2.
- Reservoir characteristics and fluid distributions — Figs. 1 and 2.
- Well conditions and their effect on near wellbore saturation distributions — Figs. 3 to 6.

To ensure data quality and representative results, a reservoir saturation monitoring program has to be fit-for-purpose and objective driven[9], as summarized in Fig. 7.

Following are recommendations in designing a fit-for-purpose monitoring program to minimize critical factors affecting the quality and results of reservoir saturation monitoring.

Well Design

1. Small wellbore observation wells are preferred to minimize the borehole effect.
2. An open hole is preferred; provided that the well can be logged under flowing conditions.
3. Fiberglass casing may be considered for time-lapse resistivity logging.
4. Perforations should be minimized and only located at strategic locations such as at the very top of a reservoir for pressure and temperature monitoring, with an understanding that near wellbore reservoir saturation across the perforations would most likely be affected by borehole fluid reinvasion.

Drilling

1. Mud properties — such as particle size distribution — are matched with reservoir rock characteristics — such as pore throat size distribution.
2. Pressure overbalance is minimized, or the target reservoir is drilled as close to being balanced as possible.
3. The well is drilled slightly deviated (10° to 20°) to ensure tool contact with the reservoir and good data repeatability among time-lapse logging.
4. The well is drilled in-gauge to minimize the borehole rugosity effect on shallow reading logs.

Cementing

1. A cementing program is carefully designed and followed to ensure good cement quality.
2. Casing is centralized to ensure cement is uniformly distributed around the casing.
3. Cement bonding quality is monitored periodically.

Time-Lapse Logging

1. Frequency of time-lapse logging is optimized depending on the location of the well with respect to field scale reservoir dynamics.
2. Using the same logging tool from a company is preferred, if possible, to conduct time-lapse logging to minimize tool design artifacts.
3. For wells with open hole completion or cased hole completion with perforations, logs are run under flowing conditions to minimize the borehole fluid reinvasion effect.

CONCLUSIONS

Based on this study, the following are concluded:

1. Due to drilling mud filtrate invasion, reservoir saturation derived from shallow measurements may not be representing reservoir saturation. A minimum of three years may be needed for the invaded mud filtrate to be dissipated.
2. Borehole fluid can reinvade back into the formation across open hole or perforations of cased hole if a pressure differential between the borehole fluid and reservoir exists, resulting in nonrepresentative measurements of shallow

logs. To minimize this effect, flow back is required.

3. For proper reservoir saturation monitoring using a C/O log in cased hole wells, good cement quality is a must, and periodic monitoring of the cement quality with field development is required.
4. Many factors may affect the quality of reservoir saturation monitoring, including the tools used, borehole conditions and borehole fluid, and the near wellbore reservoir rock and fluid conditions. A reservoir saturation monitoring program is objective driven and fit-for-purpose.

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BIOGRAPHIES

Yahia A. Eltaher is a Petrophysicist working in Saudi Aramco's Reservoir Description Division of the Northern Area Petrophysics Unit, focusing on reservoir surveillance. He has more than 10 years of experience in logging and formation evaluation. Yahia started his career with the Gulf of Suez Petroleum Co. as an Operation Petrophysicist, and then he worked for Halliburton for eight years in North Africa and the Middle East. During this period, Yahia provided support and consultation, regionally and globally, with regards to pulsed neutron logging, production logging and well integrity.

He has authored and published several technical papers.

Yahia received his B.S. degree in Geology and Chemistry from Cairo University, Giza, Egypt.

Dr. Shouxiang M. "Mark" Ma is a Senior Consultant overseeing research, technology, and professional development with the Reservoir Description Division of Saudi Aramco. He serves on the Petroleum Engineering Special Core Analysis Council and the Technologist Development Program Committee, and he champions the Logging Excellence Professional Network. Mark was Supervisor of the Petrophysical Support & Study Unit, a petrophysics professional development advisor at the Upstream Professional Development Center, and Lead Engineer for logging operations.

Before joining Saudi Aramco in 2000, he worked at the Exxon Production Research Company, Wyoming Western Research Institute, New Mexico Petroleum Recovery Research Center, and China Yangtze University.

Mark has authored or coauthored more than 70 technical papers and holds several patents. He has served on the JPT Editorial Committee since 2015, chairs the 2018 Society of Petroleum Engineers (SPE) Annual Technical Conference and Exhibition Formation Evaluation Committee, and was chairperson of the 2012-2013 SPE Formation Evaluation Award Committee. Mark is a Vice President of the newly established Saudi Arabia Chapter of the Society of Petrophysicists and Well Log Analysts.

Mark received his B.S. degree from the China University of Petroleum, Shandong, China, and his M.S. and Ph.D. degrees from the New Mexico Institute of Mining and Technology, Socorro, NM, all in Petroleum Engineering.

Mamdouh N. Al-Nasser is currently the Supervisor of the Southern Area Petrophysical Unit in Saudi Aramco's Reservoir Description & Simulation Department (RD&SD). He has over 16 years of experience, during which he has held several supervisor positions, including in the Northern Area Petrophysical, Reservoir Surveillance Petrophysics, and Gas Development Units at RD&SD, and the Uthmaniyah Unit in the Southern Area Reservoir Management Department. Moreover, Mamdouh also has held several technical positions in the Northern Area Production Engineering Department (onshore and offshore), RD&SD, the Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC), and in Southern Area Reservoir management.

Mamdouh received his B.S. degree in Chemical Engineering and his M.S. degree in Petroleum Engineering in 2002 and 2012, respectively, from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

Mamdouh has published and coauthored several technical papers. He is a Society of Petroleum Engineers (SPE) certified Petroleum Engineer.

New, Integrated Approach to Diagnose, Characterize and Locate Interwell Fracture Connectivity in Carbonate Reservoirs from Transient Test Data

Omar H. Al-Obathani, Bandar A. Al-Wehaibi, Faisal M. Al-Thawad, and Dr. N.M. Anisur Rahman

ABSTRACT

Characterization of natural fractures in carbonate reservoirs to the resolution of well tests is reliable for major fracture corridors. These fracture corridors, intersecting or nonintersecting the wells, impact the well's performance and the ultimate recovery in the field. Good transient test data is the key to diagnosing fractures and their characteristics. When fractures exist between the wells, it requires some additional efforts in locating these with respect to the wells.

To overcome this challenge we propose a new approach of building 3D numerical models to diagnose and characterize the interwell fracture corridors. In addition, these 3D multiwell numerical models are to determine the location and the extent of fracture corridors by utilizing dynamic pressure transient data. The innovative idea of bringing multiple wells to the models to consider interference of wells and fracture corridors makes the models robust.

We have been able to identify the interwell fracture corridors successfully in carbonate reservoirs by performing pressure transient analyses on wells. By adjusting the interwell locations of fracture corridors and the extent of these fracture corridors in the multiple well models, we try to achieve the best possible matches with the transient pressure data. This integrated approach will provide essential input to 3D full-field reservoir models, and will lead to optimizing field management.

INTRODUCTION

Fracture identification and characterization of naturally fractured reservoirs to the resolution of well tests is reliable, especially when major fracture corridors exist within the radii of investigation. These fracture corridors, intersecting or nonintersecting the wells, impact the well's performance in both the short- and long-term. Because the conductivity of fracture corridors is substantially higher than that of the matrix, the fracture corridors tend to dominate the flow in the subsurface geological settings. A proper characterization is key to proper well placement and good reservoir management practices by delaying early water breakthroughs. With a good understanding of the fracture corridors and their spatial distribution, the associated challenges can be transformed into opportunities to maximize the recovery of hydrocarbons and to minimize the costs.

Good transient test data is paramount to diagnosing fractures, and their characteristics, locations, orientations, and extent, because a transient pressure test is one the most reliable sources of gathering dynamic data for reservoir characterization and fracture identification. Moreover, pressure transients have the ability to propagate up to a few kilometers in the reservoir, providing extremely valuable data away from the wellbore within the radii of investigation. This data is essential to characterize the interwell heterogeneity in the field scale, unlike other limited coverage of logs, cores, and possible poor resolution of seismic attributes. Al-Thawad et al. (2001)[1] have attempted to characterize faults and fractures from well test data by recognizing standard flow regimes on log-log plots.

When fractures exist between the wells, some additional efforts are required in locating these fractures with respect to the wells, and in determining the extent of fractures. To overcome these challenges, we propose a new approach of building 3D numerical models to diagnose and characterize the interwell fracture corridors. In addition, these 3D multiple well numerical models are to determine the location and the extent of fracture corridors by utilizing dynamic pressure transient data. The innovative idea of bringing multiple wells to the models to consider the interference of wells and fracture corridors makes the models robust.

We have been able to identify the interwell fracture corridors successfully in carbonate reservoirs by performing pressure transient analyses on wells. The interwell locations of fracture corridors and the extent of these fracture corridors are calibrated by the transient pressure data from multiple wells in the area of interest. The outcome of this approach is presented as a deterministic 2D map for the fracture corridor network, based on the compliance with actual dynamic pressure transient data of all the wells in the area of interest. The quality matches, with the diagnostic log-log plots of pressure derivative and difference for these wells, located in the vicinity of the same fracture network, testify the strengths of this approach. This integrated approach based on pressure transient models will provide essential input to 3D full-field reservoir simulation models for better history matching, and will lead to optimizing the field management, well placement and ultimate recovery of hydrocarbons.

METHODOLOGY

This study proposes a workflow involving multiple wells that takes advantage of the power of pressure transient analysis in fracture identification and characterization, whenever fractures exist between the wells. The workflow requires integration of pressure transient data of all the wells in the area of interest, Fig. 1. Fracture conductivity, length, orientation, and extent are predictable from this workflow through a modeling approach. By building numerical models, matches are sought to the transient pressure data. The quality of the matches are reviewed on the log-log diagnostics plots of pressure derivative and difference, eventually leading to interpretation and characterization of the fracture network.

This approach consists of two major steps. The first step is to utilize analytical solutions to a well near a nonintersecting conductive fracture to estimate the distance to the fault for each well in the area of interest. Upon completion of the first step, the analyst will have a good idea on the fracture characteristics. The second step is to build numerical models of the wells in the area of interest with the same data used in the first step. This time, the primary objective is to calibrate the map of fracture corridors. Such a map is created with fracture orientations from seismic data and fracture corridors from wellbore image logs of the field. Note that these numerical models are updated with the dynamic characteristics of fractures as determined in the first step. The numerical models may need to be reworked so that the model results match the corresponding well test data of each well. Displaying log-log plots should confirm the quality of the match between the model pressures and the measured well test pressures. Finally, acceptable numerical models are built through an iterative process. Relevant fracture characteristics can be extracted from the final numerical models and the fracture corridor map.

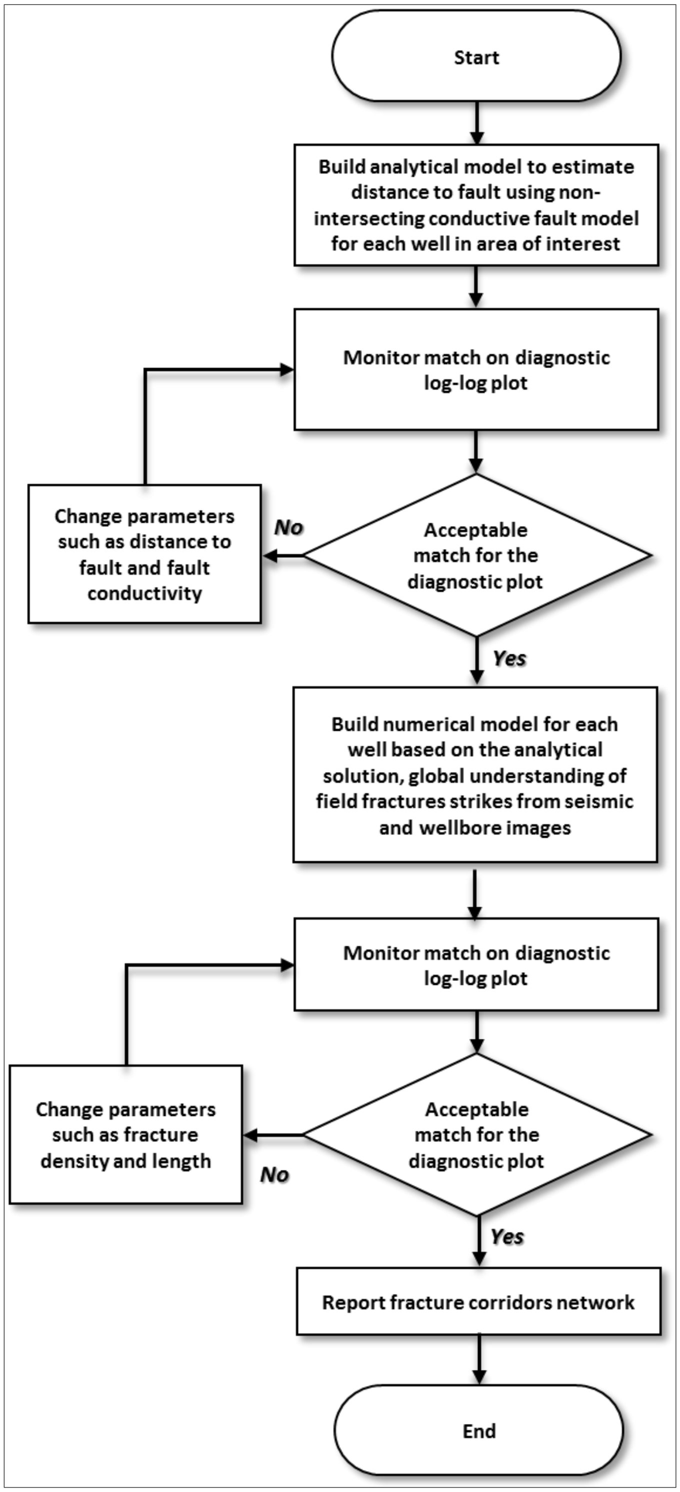

Fig. 1. Proposed workflow to characterize interwell fracture corridors.

CASE STUDIES

The workflow described in Fig. 1 has been utilized in a study of three vertical wells with reliable pressure transient data in the area of interest. The relative locations of the subject wells — Wells A, B, and C — are shown in Fig. 2. According to the field-based global understanding of wellbore image logs and seismic attributes, the orientations of global major fracture strikes tend to align along the NE/SW and NW/SE. The average pay thickness of the naturally fractured carbonate reservoir is about 170 ft, and the average permeability is about 200 md.

In the transient pressure data of three wells, there are three major flow regimes that belong to the middle time region, and

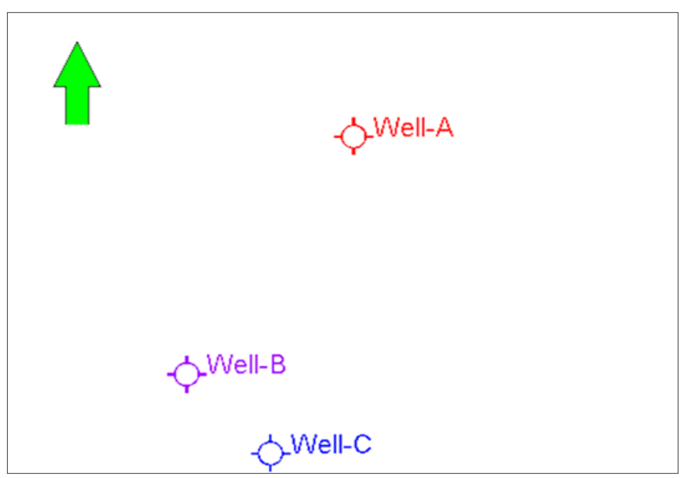

Fig. 2. A 2D map of the study area of interest showing the three wells: Wells A, B, and C.

are identified in the diagnostic log-log plots. The first of these three regimes is the infinite acting, radial flow regime as identified by a zero slope line. The second one is the pressure support regime with a negative unit slope line, and the third one is the bilinear flow regime caused by the simultaneous linear flow in both matrix and conductive fracture corridors as identified by a quarter slope line. Note that the third flow regime can turn out to be the linear flow regime if the fracture has infinite conductivity, instead of finite conductivity. Du and Stewart (1995)[2] elaborated with field examples on the appearance of bilinear flow regimes as identified in systems with high conductivity faults near vertical wells.

As discussed earlier, in the workflow of this study, there are two major steps to follow: (1) Utilization of an analytical solution to estimate fracture properties, and (2) Utilization of a numerical solution to build the map of the fracture corridor network in the area of interest.

These steps are systematically followed in the cases presented next.

ANALYTICAL MODELS

Three cases are discussed to illustrate the methodology of using an analytical solution.

Well-A

Well-A is a vertical, dry oil producer, located in the northern side of the study area, Fig. 2. The well was completed as an open hole well in a carbonate limestone reservoir.

Based on the stabilization of the radial flow regime, the flow capacity of the drainage area around the wells is about 500,000 md-ft, which is an order of magnitude higher than the average flow capacity in the field. This high flow capacity value may be attributed to the presence of highly conductive natural fractures around the wellbore that have greatly influenced the pressure transients.

As per the workflow, an analytical solution to identify a well near a nonintersecting conductive fault model has been utilized to match the data. A comparison of the model pressures and the measured transient pressures is presented in Fig. 3. The model suggests that Well-A is located at an estimated distance of 300 ft to a conductive fault. Note that it requires the matching of the first two flow regimes (radial flow and pressure support regimes) in the middle time region of the data to calculate the distance to the conductive fault.

Well-B

Well-B, completed as an open hole, is also a vertical, dry oil producer, located in the southern part of the area of interest, Fig. 2. The log-log plot, Fig. 4, shows only two main flow regimes, the radial flow and the pressure support ones. As the test duration has not been long enough, the bilinear flow regime

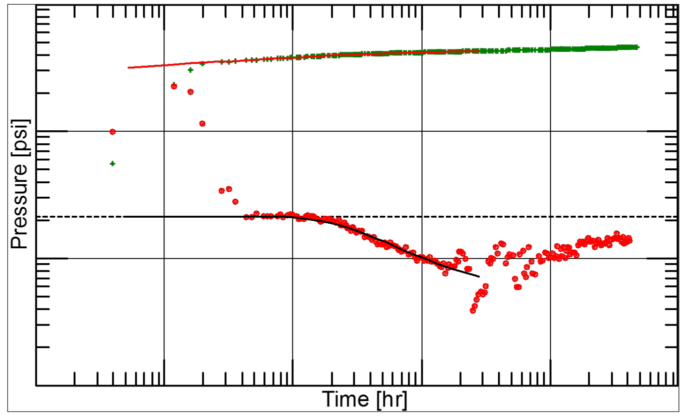

Fig. 3. Diagnostic log-log plot with a match of the data for Well-A using an analytical solution to estimate the distance to the fault.

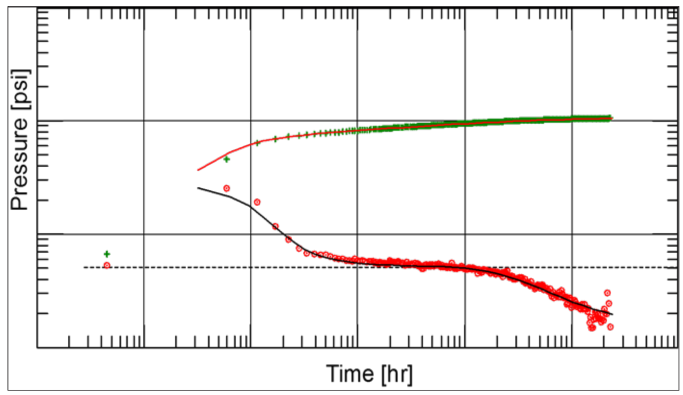

Fig. 4. Diagnostic log-log plot with a match of the data for Well-B using an analytical solution to estimate the distance to the fault.

cannot be observed here. The flow capacity of Well-B as estimated from the radial flow regime is about the same as that of Well-A, which can be attributed to the presence of conductive features around Well-B. The diagnostic pressure derivative plot in Fig. 4 shows successful matching of the test data with the output of an analytical solution of a well near a nonintersecting conductive fault. The matched model suggests that the fracture corridor is located at about 1,250 ft away from Well-B.

Well-C

Well-C, completed as an open hole, is a vertical, dry oil producer, located in the southeastern section in the area of interest, Fig. 2. Figure 5 shows the log-log plot of data of Well-C; the radial flow regime has been masked by the wellbore storage and the transition thereafter. Although, two other main flow regimes are observed in the pressure derivative plot of Well-C. These flow regimes are the pressure support and the linear flow regime — indicating an infinitely conductive fracture. From the match of the data here, it is concluded that the fault is only 50 ft away from Well-C.

NUMERICAL MODEL FOR FRACTURE CORRIDORS

Nominal distances to the respective fracture in Wells A, B, and C as estimated earlier with an analytical solution, did not

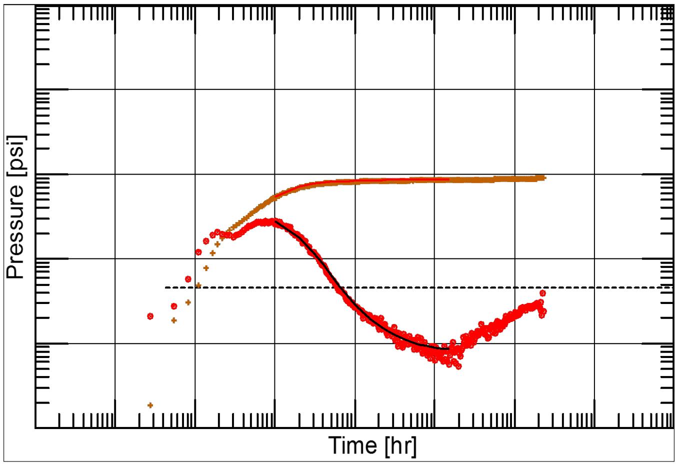

Fig. 5. Diagnostic log-log plot with a match of the data for Well-C using an analytical solution to estimate the distance to the fault.

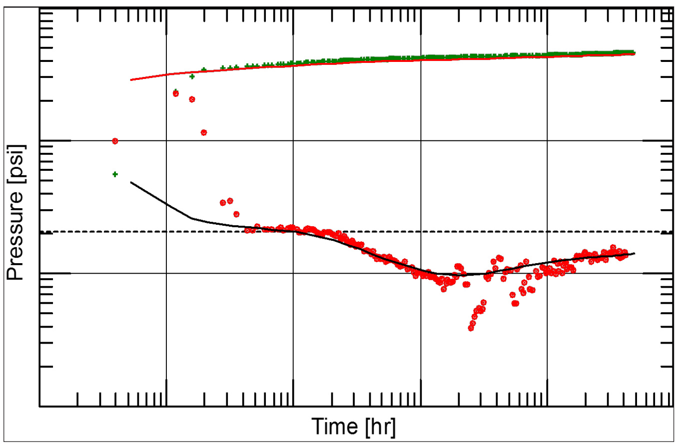

Fig. 6. Diagnostic log-log plot with match of Well-A data using a numerical solution to calibrate the fracture network.

provide much information on the orientation of each fracture. To narrow down the uncertainty, building numerical models with the background of a map of fracture corridors is essential to identify the orientation of interwell fracture corridors on a spatial distribution. An initial version of such a map is created from seismic data and image logs.

Based on the analytical solution analysis and field global understanding of the fracture strikes, the orientation and directions from seismic information, and the wellbore image analysis, the spatial distribution of fracture network has been successfully identified, confirmed and calibrated with matching of the dynamic transient pressure data from the three wells in the area of interest. The results of the matched data with the numerical model are presented in Figs. 6 to 8 for Wells A, B, and C, respectively. These numerical models have finally reduced the uncertainty on the distribution of fractures in the area of interest by creating a fracture corridor map, Fig. 9.

CONCLUSIONS

Interwell fracture corridors can be identified and characterized, using actual dynamic pressure transient data. The proposed multi-well integrated workflow has taken advantage of

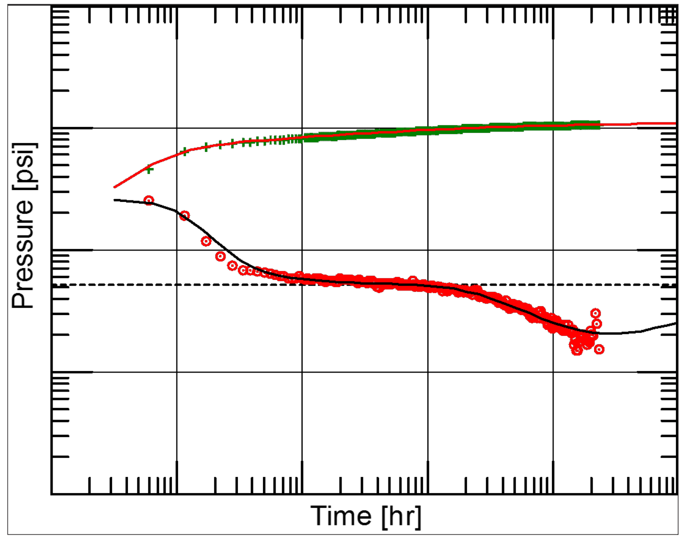

Fig. 7. Diagnostic log-log plot with match of Well-B data using a numerical solution to calibrate the fracture network.

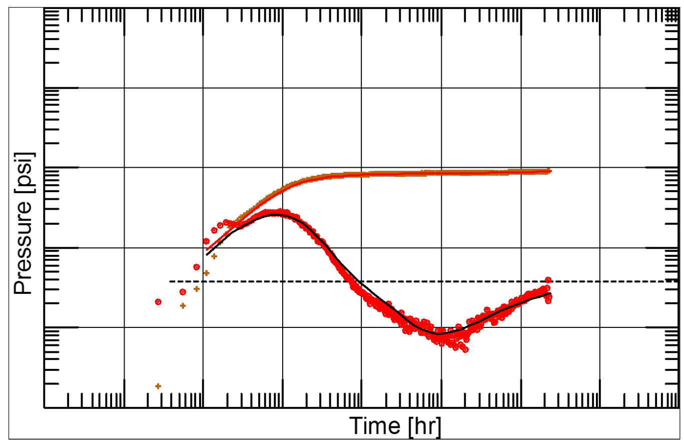

Fig. 8. Diagnostic log-log plot with match of Well-C data using a numerical solution to calibrate the fracture network.

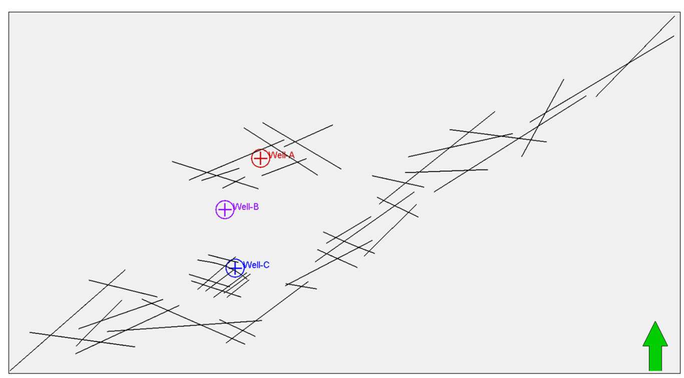

Fig. 9. Fracture corridors in the area of interest calibrated with analytical and numerical models using well test data from Wells A, B, and C.

the capability of the dynamic pressure transient data to identify and map the fracture corridors away from the wellbore. Such a dynamic characterization of fracture corridors cannot be accomplished with the interpreted seismic data alone.

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BIOGRAPHIES

Omar H. Al-Obathani is a Petroleum Engineer in the Well Testing Division of Saudi Aramco's Reservoir Description and Simulation Department. He has worked for Saudi Aramco for the last 12 years in the petroleum engineering domain. Currently, Omar is responsible for building advanced transient models for calibrating geological models with transient test data. His interests include reservoir simulation models and pressure transient analysis.

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

Bandar A. Al-Wehaibi is a Petroleum Engineer with Saudi Aramco's Reservoir Description and Simulation Department. Since joining the company in 2001, he has worked in several different disciplines in petroleum engineering, including drilling, production, petrophysics, and simulation and well testing. Over the last 10 years, Bandar has specialized in pressure transient testing and has worked on many projects involving the analysis of complex reservoir environments using integrated pressure transient analysis and advanced numerical well testing. Also, he has been involved in designing and analyzing pulse and interference tests for new fields in the development stages in Saudi Arabia.

Bandar is a Society of Petroleum Engineers (SPE) certified Petroleum Engineer.

He received his B.S. degree in Petroleum Engineering from King Saud University, Riyadh, Saudi Arabia, and an M.S. degree in Petroleum Engineering from the University of Calgary, Calgary, Alberta, Canada.

Faisal M. Al-Thawad is a General Supervisor of the Well Testing Division and a Senior Consultant in pressure transient analysis in Saudi Aramco's Reservoir Description and Simulation Department. He has extensive experience in operations and supervision of exploratory tests, and in transient modeling of faults and fractures and multilateral wells.

Faisal has more than 27 years of experience in various petroleum disciplines, including drilling, reservoir management and simulation, and he also completed a 6-year Specialist Development Program on "Reservoir Testing/New Technologies" with a focus on fracture identification, characterizing and modeling.

Faisal has authored several technical papers in the field of well testing and pressure transient analysis.

He is a member of the Society of Petroleum Engineers (SPE) and has participated in a number of international conferences. Faisal was a SPE Distinguished Lecturer during the 2013/2014 cycle, delivering the lecture "Fractures Network: Reservoir's Friend or Foe?" He participated as a panelist and was a speaker invited to deliver expert opinions and speeches at many national and international technical meetings and at universities.

Faisal received his B.S. degree in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, and his M.S. degree in Petroleum Engineering from Heriot-Watt University, Edinburgh, U.K. Currently, Faisal is finalizing his Ph.D. degree with a dissertation on Fracture Network Modeling at Heriot-Watt University.

Dr. N.M. Anisur Rahman is a Senior Petroleum Engineering Consultant with the Well Testing Division of the Reservoir Description and Simulation Department at Saudi Aramco, where he designs and interprets transient tests on hydrocarbon production and water injection wells. Anisur Rahman has also developed analytical solutions to a number of pressure transient models, including methods for short well tests. His interests include production technology, reservoir characterization and pressure transient analysis.

Prior to joining Saudi Aramco in 2009, Anisur Rahman worked for the Bangladesh University of Engineering and Technology, the University of Alberta, Fekete Associate Inc., and Schlumberger.

He has authored or coauthored 34 technical papers for publication in refereed journals and conference proceedings, and eight patent documents, of which two patents have already been granted by the U.S. Patent and Trademark Office. Anisur Rahman was a recipient of the 2016 Society of Petroleum Engineers (SPE) Middle East Regional Reservoir Description and Dynamics Award for his contributions to exceptional service and leadership, and for making significant contributions to the technical discipline. He also serves as a PTA/Well Testing Champion under the Petroleum Engineering Technical Excellence (PETE) and Support Network in Saudi Aramco.

Anisur Rahman received both his B.S. and M.S. degrees in Mechanical Engineering from the Bangladesh University of Engineering and Technology, Dhaka, Bangladesh, and his Ph.D. degree in Petroleum Engineering from the University of Alberta, Edmonton, Alberta, Canada.

He is registered as a Professional Engineer in the Province of Alberta, Canada.

Emulsifier Developed from Waste Vegetable Oil for Application in Invert Emulsion Oil-based Mud

Dr. Jothibasu Ramasamy, Dr. Md. Amanullah, and Mujtaba M. Al-Saihati

ABSTRACT

Emulsifiers are a class of chemicals derived from fatty acids or their derivatives and used in water- and oil-based mud (OBM) — an invert emulsion. The role of an emulsifier in invert emulsion OBM is to lower the interfacial tension between water and oil to allow the formation of stable emulsion, which is an essential quality of the OBM. These emulsifiers surround the water droplets like an encapsulation with the fatty acid components extended into the oil phase, which acts like a small osmatic cell allowing only water to pass through, but not salts. Most of the commercially available emulsifiers are derived from tall oil fatty acids, which shows excellent emulsion stability even at harsh conditions.

Our objective in this study is to make use of the huge quantity of used cooking/vegetable oil available in the Kingdom and convert this to an emulsifier suitable for the application in invert emulsion OBM; vegetable oil contains a wide range of different fatty acids in the form triglycerides. A comparative study has been carried out by formulating invert emulsion OBM using commercially available emulsifiers and the emulsifier derived from used cooking/vegetable oil. An emulsifier, Arc-Eco-Mul, from used or waste vegetable oil has been synthesized by an in-house developed process. A series of different invert emulsion OBMs have been formulated with varying density, using the in-house developed product Arc-Eco-Mul as the primary emulsifier. For comparison, a mud is formulated using a commercial primary emulsifier. Then, all the formulations were tested for mud properties such as density, rheology, and API. High-pressure, high temperature (HPHT) filtration control tests were conducted for fresh mud and for muds hot rolled at 300 °F and 500 psi for 16 hours. It was observed from the laboratory experiments that the mud samples formulated using 12 ppb of Arc-Eco-Mul, have similar rheological properties and better filtration control properties compared to the mud samples formulated using 12 ppb of a commercial emulsifier. Most importantly, there is no phase separation in the filtrate collected from the HPHT filtration control experiment, which showed a very stable emulsion formed by the Arc-Eco-Mul. Concentration screening experiments showed that only 6 ppb loading of Arc-Eco-Mul is required to achieve a mud with very good rheological and filtration control properties with high emulsion stability.

The in-house developed Arc-Eco-Mul from used cooking/vegetable oil has similar properties as commercial additives that are currently used in the industry. This will open an avenue for recycling used cooking/vegetable oil for oil and gas industry applications.

INTRODUCTION

Invert emulsion fluids have been used for drilling trouble prone zones such as reactive shale sections, hard rock formations, etc., to provide a high rate of penetration, reduction in downhole losses, shale stability and increased tolerance to contamination[1]. The invert emulsion fluid consists of a three liquid system, such as oil as a continuous phase, brine as a discontinuous phase, and surfactants or emulsifiers that stabilize the dispersion of the continuous and discontinuous phase[2]. An emulsion is formed at the interface of the continuous and discontinuous phase by lowering the interfacial surface tension of one liquid. This is achieved by using an emulsifier to enable the formation of stable dispersion of fine droplets in the other liquid. The lower the interfacial tension and the smaller the size of the droplets will lead to more stable emulsion. Calcium hydroxide (lime) is used to activate the emulsifier by maintaining reverse alkalinity.

Emulsifiers are a class of surfactants that are characterized by having polar functional groups. Examples of such surfactants are fatty acids, amine-based surfactants[3] and fatty alcohols. Fatty acids are types of emulsifiers that were applied in the oil field. The emulsification performance of fatty acids are activated by lime to form a calcium soap. Tall oil has been the main source of these emulsifiers for oil field application. The most commonly found fatty acids in tall oil is stearic acid and palmitic acid, along with linoleic acid, Fig. 1. Two additional improvements in terms of emulsion stability, wettability and other properties, are amine-based emulsifiers, e.g., imidazoline and polyamine.

The stability of an invert emulsion is not only due to the chemical stability of the emulsifier and the internal phase, but also depends on the interfacial interactions of solid materials such as weighting agents, fluid loss control agents and other solids such as drill solids. Organophilic clays, which are used as viscosifiers for invert emulsion fluids, have an impact on emulsion stability as well.

Vegetable oil is a triglyceride, extracted from a plant. Triglycerides are an ester of glycerol and three fatty acids, Fig. 2. Depending on the source, vegetable oil contains a mixture of different types of fatty acids such as saturated, mono unsaturated, poly unsaturated, omega 3, omega 6, or omega 9. Most of the commonly used oils that are used for cooking, including olive oil, palm oil, sunflower oil, corn oil, and peanut oil, contain most of these fatty acid types.

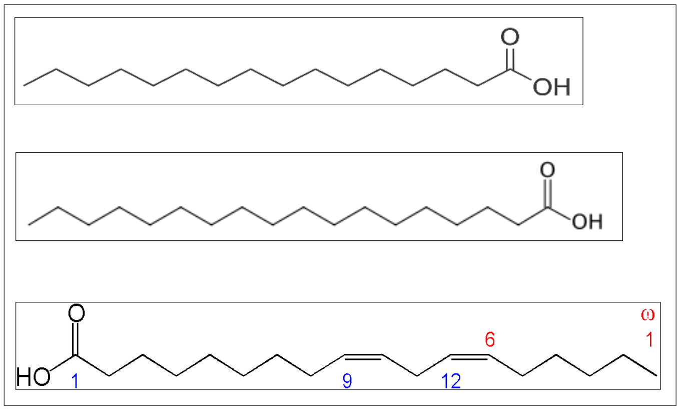

Fig. 1. Palmitic acid (top), stearic acid (middle), and linoleic acid (bottom).

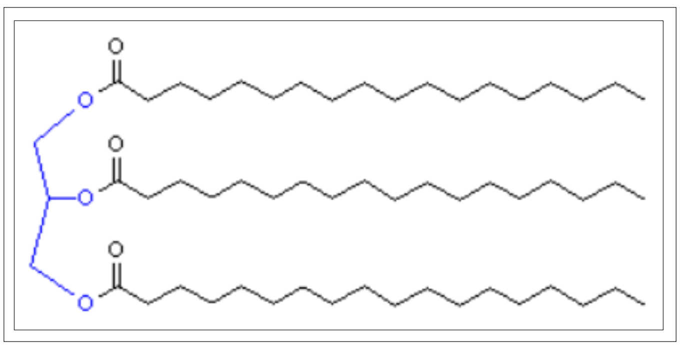

Fig. 2. Triglycerides (vegetable oil) are an ester of glycerol and three fatty acids.

Vegetable oil is a promising source for emulsifiers as they have different types of fatty acids in the form of triglycerides. Subsequently, the use of pure and fresh vegetable oil as a raw material for the synthesis of emulsifiers is not a viable option. On the other hand, vegetable oils that are already used for cooking and are disposed of as waste, could be used as a sustainable source for the development of potential products for oil field applications such as lubricants[4, 5] and biodiesel[6-8].

The objective of the study presented in this article is the application of emulsifiers derived from waste vegetable oil for invert emulsion oil-based mud (OBM) systems.

METHODS AND MATERIALS

An emulsifier, Arc-Eco-Mul, from used or waste vegetable oil has been synthesized by an in-house developed process. The waste vegetable oil of different types have been collected and mixed. An initial filtration process has been carried out to remove any solid food debris in the oil. The oil has then been chemically treated and transformed to yield the emulsifier. The emulsifier has then been isolated from the reaction mixture using a series of steps. The obtained emulsifier is a light-brown colored liquid, which was used for the study in this article. For comparison of the performance of the emulsifier prepared from waste vegetable oil, a commercially available

Mud System	Formulation Using Commercial Emulsifier	Formulation ARC-Eco-Mul
Safra oil (ml)	218	218
Commercial emulsifier (ml)	12	0
ARC-Eco-Mul (ml)	0	12
EZ-mul (ml)	4	4
Lime (g)	6	6
Geltone (g)	4	4
Duratone (g)	6	6
Brine (61 g $CaCl_2$ in 85 cc water) (ml)	85	85
Barite (g)	161	161
Mud properties after hot rolling for 16 hours at 300 °F and 500 psi		
Plastic viscosity	22.9	24.2
Yield point	9.2	11.2
Electrical stability	295	102
API spurt loss (ml)	0	0
API fluid loss (ml)	0	0
HPHT spurt loss (300 °F and 500 psi) (ml)	0.4	0
HPHT fluid loss (300 °F and 500 psi) (ml)	5.6	3.4

Table 1. Comparison of emulsifier performance

emulsifier has been chosen for comparative study. As compared to the commercial emulsifier, the prepared emulsifier is less viscous. Therefore, there is no need to dilute using solvents as in the case of commercial emulsifiers. This will lower the required transportation as well as storage space. The initial screening was carried out using 12 ppb of emulsifier concentration to make sure the vegetable oil derived emulsifier really performs well. Then a series of different invert emulsion OBMs were formulated with varying density, and concentration, using Arc-Eco-Mul as the primary emulsifier. All the formulations were then tested for mud properties such as density, rheology, and API. High-pressure, high temperature (HPHT) filtration control tests were conducted for fresh mud and for muds hot rolled at 300 °F and 500 psi for 16 hours.

RESULTS AND DISCUSSION

Table 1 shows the formulation of the invert emulsion OBM for performance comparison of the commercial emulsifier, and the Arc-Eco-Mul. Safra oil is used as the continuous oil phase, and 12 ppb of each emulsifier is used in the formulation. Other additives in the formulation are organophilic clay, secondary emulsifier, fluid loss additive, weighting agent, lime, and brine.

The results from the comparison of formulations made using the commercial emulsifier and ARC-Eco-Mul as a primary emulsifier are also shown in Table 1. Both formulations show very good rheological properties measured using mud that were hot rolled for 16 hours at 300 °F and 500 psi. The HPHT experiments were carried out 300 °F and 500 psi. The ARC-Eco-Mul formulation show better spurt loss control and fluid loss control as compared to the invermul formulation. More importantly, the filtrate obtained from the ARC-Eco-Mul formulation filtration control experiment show no phase separation of oil and water. This confirms the formation of stable emulsion by ARC-Eco-Mul even at HPHT conditions. Figure 3 shows the HPHT spurt and fluid loss difference between the commercial emulsifier and the Arc-Eco-Mul formulation.

Once proven, the application of Arc-Eco-Mul as the primary emulsifier was decided. A concentration screening was carried out to identify the optimal concentration required to provide stable emulsion while maintaining proper mud properties. A series of mud formulations were made using 12 ppb, 6 ppb, 4 ppb, and 0 ppb. Table 2 shows the formulation and

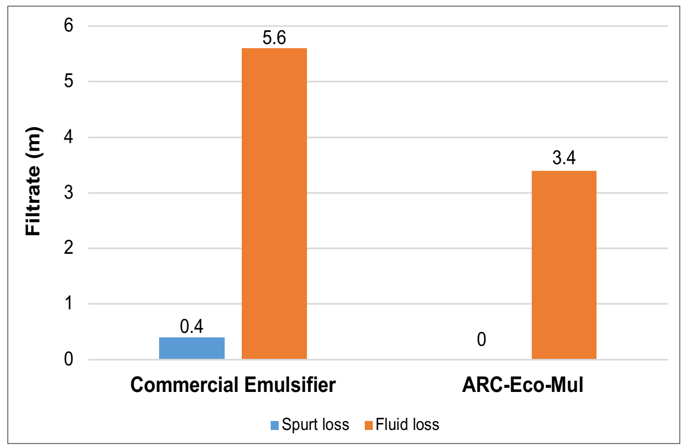

Fig. 3. HPHT spurt and fluid loss of the commercial emulsifier and ARC-Eco-Mul formulation.

Mud System				
Oil/Water Ratio	**70/30**	**70/30**	**70/30**	**70/30**
Safra oil (cc)	218	218	218	218
ARC-Eco-Mul	12	6	4	0
EZ-mul (cc)	4	4	4	4
Lime (g)	6	6	6	6
Geltone (g)	4	4	4	4
Duratone (g)	6	6	6	6
Brine (61 g $CaCl_2$ in 85 cc water)	85	85	85	85
Barite (g)	161	161	161	161
Mud properties after hot rolling for 16 hours at 300 °F and 500 psi				
Plastic viscosity	24.2	35	34	30
Yield point	11.2	12	17	30
API spurt loss (ml)	0	0	0	0.2
API fluid loss (ml)	0	1	2	9.3*
HPHT spurt loss (300 °F and 500 psi)	0	2	6*	8*
HPHT fluid loss (300 °F and 500 psi)	3.4	7	18*	68*

*Phase separation in the filtrate

Table 2. Concentration screening of the Arc-Eco-Mul emulsion

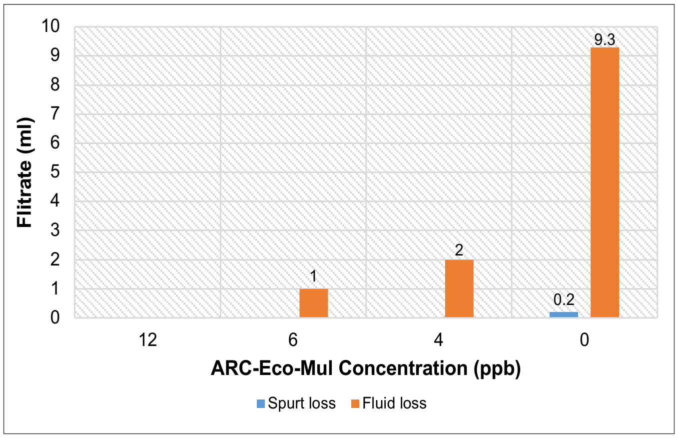

Fig. 4. Spurt and fluid loss for the API filtration control properties of the ARC-Eco-Mul.

the results.

Figure 4 shows that the 12 ppb, 6 ppb, and 4 ppb of the ARC-Eco-Mul emulsion concentration show good spurt and fluid loss for the API filtration control properties as expected for a good invert emulsion OBM. For the HPHT experiments carried out 300 °F and 500 psi, as the concentration of the ARC-Eco-Mul decreased from 12 ppb to 0 ppb, the spurt loss increased from 0 ml to 8 ml, Fig. 5a. A similar trend is observed in the HPHT fluid loss; however, the effect of reduction in concentration of ARC-Eco-Mul is very significant. A fluid loss of 3.4 ml and 7 ml were observed for formulations having 12 ppb and 6 ppb of ARC-Eco-Mul, Fig. 5b, with no phase separation observed in the filtrate in both cases even after 24 hours, Fig. 6a. This shows the superior performance of the ARC-Eco-Mul to generate stable emulsion even at HPHT conditions. A sharp increase in fluid loss (18 ml) is observed for the formulation having 4 ppb of ARC-Eco-Mul, Fig. 5b, and phase separation is observed in the filtrate, Fig. 6b. In the case of the 0 ppb ARC-Eco-Mul formulation, the spurt and fluid loss were 8 ml and 68 ml, respectively, Figs. 5a and 5b, and the filtrate showed distinct oil and water phase separation, Fig. 6c, as expected.

This observation clearly demonstrates the importance of the ARC-Eco-Mul emulsion to have good rheological and filtration control properties of the mud formulation. From these

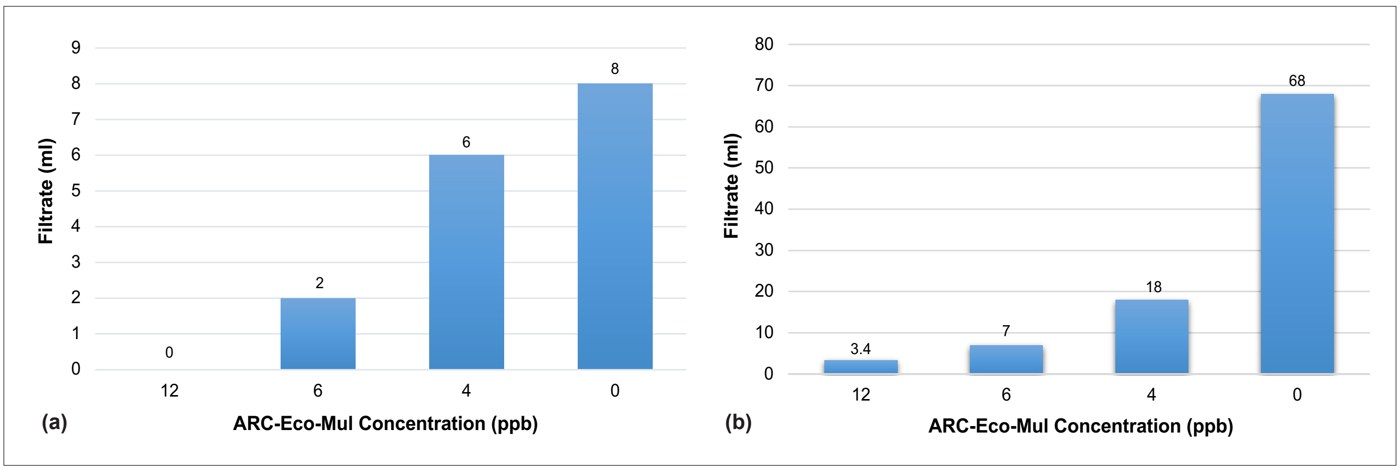

Fig. 5. HPHT spurt loss (a), and HPHT fluid loss (b).

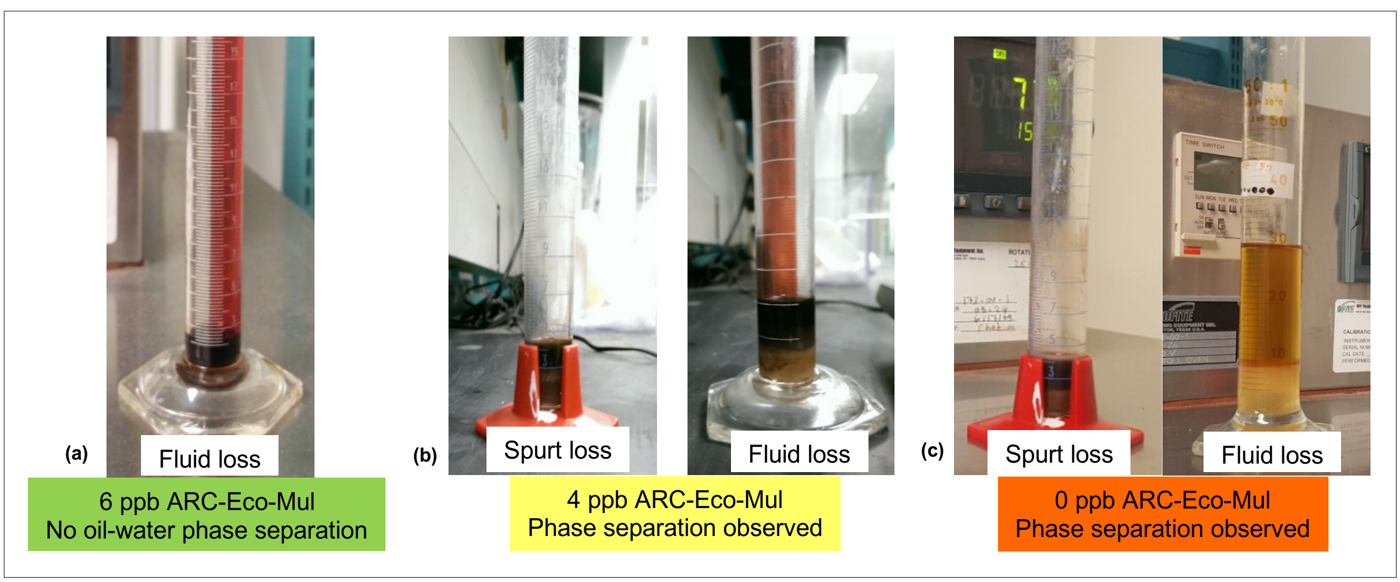

Fig. 6. Results of the HPHT fluid loss experiments of the ARC-Eco-Mul emulsion. At 6 ppb, there is no oil-water phase separation (a), at 4 ppb, phase separation is observed (b), and at 0 ppb, a distinct oil-water separation is seen (c).

experiments, it is identified that 6 ppb of ARC-Eco-Mul is the ideal concentration to have as an invert emulsion OBM with good rheological and filtration control properties, along with good emulsion stability.

CONCLUSIONS

In summary, a new emulsifier has been developed from waste or used vegetable oil. The comparison study with a commercial emulsifier revealed that the newly developed emulsifier, Arc-Eco-Mul, has similar mud properties as well as filtration control properties. The single phase of the filtrate collected from the HPHT fluid loss experiment proved the emulsion stability provided by Arc-Eco-Mul. Concentration screening of this new emulsion showed that 4 ppb and 0 ppb are not suitable concentrations for use.

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BIOGRAPHIES

Dr. Jothibasu Ramasamy is a Petroleum Scientist working with the Drilling Technology Team of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). He joined Saudi Aramco in July 2013. Prior to this, he worked as a Research Fellow with the Department of Chemistry at the National University of Singapore and as a Postdoctoral Fellow with the Catalysis Center at the King Abdullah University of Science and Technology (KAUST), Saudi Arabia.

Jothibasu received his B.S. degree in Chemistry from Bharathidasan University, Tiruchirappalli, India, and his M.S. degree, also in Chemistry, from Anna University, Chennai, India. In 2010, he received his Ph.D. degree in Chemistry from the National University of Singapore, Singapore.

Jothibasu has published 15 technical papers and filed three patents.

Dr. Md. Amanullah is a Senior Petroleum Engineering Consultant working at Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC). Prior to joining Saudi Aramco, he worked as a Principal Research Scientist at CSIRO in Australia.

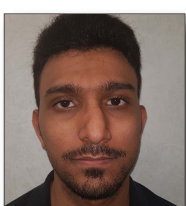
Aman is the lead inventor of a vegetable oil-based dielectric fluid (patented) that led to the formation of a spinoff company in Australia for commercialization of the product.

He has published more than 100 technical papers and filed more than 50 patents, with 16 already granted. Two of Aman's patents were highlighted in scholarly editions of two books published in the U.S.

He is one of the recipients of the 2005 Green Chemistry Challenge Award from the Royal Australian Chemical Institute. Aman also received the CSIRO Performance Cash Reward in 2006, the Saudi Aramco Mentorship Award in 2008 and 2010, the World Oil Certificate Award for nano-based drilling fluid development in 2009, the Intellectual Asset Recognition Award in 2014, and the Award of Recognition for Outstanding Contribution to the success of agricultural waste and environmental protection in 2014. His date tree waste-based product development was highlighted in *The Arabian Sun*, the *Arab News* and also in the Al Riyadh newspaper.

Aman is a member of the Society of Petroleum Engineers (SPE). He received the SPE Regional Service Award in 2014 and also the SPE Middle East Drilling Engineering Award in 2016 for his contribution to the industry. Aman also received the Middle East Oil and Gas Technical Innovation of the Year Award in 2017, and in 2018, he received the Board of Engineers Recognition Certificate for Date Seed-based ARC Plug development.

Aman received his M.S. degree (First Class) in Mechanical Engineering from the Moscow Oil and Gas Institute, Moscow, Russia, and his Ph.D. degree in Petroleum Engineering from Imperial College, London, U.K.



Mujtaba M. Al-Saihati is a Lab Technician working with Drilling Technology Team of Saudi Aramco's Exploration and Petroleum Engineering Center – Advanced Research Center (EXPEC ARC).

He has published one technical paper and filed one patent.

Mujtaba received his training from Saudi Aramco's Industrial Training Center (ITC) and Jubail Industrial College, Jubail, Saudi Arabia.

Customized Drilling Fluids Design to Drill Challenging Sections Using High Performance Water-based Mud

Rafael M. Pino Rojas, Ihab M. El-Habrouk, Ajay Kumar V. Addagalla, and Prakash B. Jadhav

ABSTRACT

This article presents a customized water-based drilling fluids design for drilling challenging sections through varying formations. The offset wells were reviewed to identify the issues while drilling the trajectory through troublesome reactive and depleted formations that showed wellbore stability issues, stuck pipe incidents, and induced severe losses.

Additional problems experienced while drilling include shale dispersion, resulting in fine solids buildup in the drilling fluid, and the adherence of shale to the drillpipe and bit, reducing penetration rates. The customized drilling and completions fluids system was designed for different intervals. The system was developed with the following objectives in mind: improved hole stability through reactive formations; enhanced hole cleaning efficiency at critical angles; minimized risk of stuck pipe across depleted formations with high porosity and permeability; minimized or non-induced losses to the formation utilizing a unique wellbore strengthening technique; and improved rate of penetration (ROP) to optimize drilling efficiency.

This article describes the customized high performance water-based mud (HPWBM) design and performance. A comprehensive engineered approach addressed the challenges of drilling horizontal wells by using a high performance aluminum complex and polyamine chemistry to improve wellbore stability.

This approach for drilling fluid chemistry provides an alternative replacement for previously used non-aqueous drilling fluids. Three wells were drilled successfully, and the lessons learned on these wells were incorporated in drilling subsequent wells to continue improving drilling performance.

INTRODUCTION

In recent years, high performance water-based mud (HPWBM) has been developed as a substitute for oil-based mud (OBM), but not all types of HPWBM have been able to replace OBM in more challenging wells. With the ever-increasing drive toward better environmental performance and the increased restraint on the discharge of OBM cuttings, there is a drive in the oil and gas industry to develop a water-based mud (WBM) that provides performance comparable to OBM. One of the main characteristics of HPWBM is the similarity on performance compared to OBM, including rates of penetration (ROP), shale inhibition and wellbore stability. Conventional WBM needs to show an increase in performance to merit the description of HPWBM.

Similar OBM performance is achieved because the HPWBM is designed with an understanding of the attributes that OBM provides in terms of inhibition mechanism.

SHALE STABILITY

Shales comprise a large percentage of the formations drilled, with shale instability being the root cause of the vast majority of the wellbore instability-related problems. The most important variable in maintaining shale stability is preventing pressure invasion into the shale matrix[1, 2].

Pressure invasion alters the near wellbore stress state and can induce failure in the shale. Shale stability is achieved when pressure invasion is reduced and differential pressure support is maintained at the wall of the wellbore. Pore pressure transmission in shale is reduced by the creation of a semi-permeable membrane and an osmotic differential pressure between the shale and drilling fluid[3, 4].

OBM generates a semi-permeable — selective — membrane through the oil film and emulsifiers/surfactants surrounding the emulsion. Pressure invasion in shale when using OBM decreases due to the high concentration of salt used in the internal phase by the capillary entry pressure that must be overcome to force oil into the water-wet pore throat.

The shale matrix can be made more selective, further reducing the mobility of solids and fines by sealing the shale's microfractures. This is achieved by the use of a small and deformable sealing polymer to mechanically bridge the microfractures present in the shale. Using aluminate chemistry generates an internal bridge by precipitation within the shale through fractures. This aluminate complex is soluble in the HPWBM, but it precipitates as it enters the shale matrix due to the reduction in pH.

CLAY AND CUTTINGS INHIBITION

OBM is the ideal fluid for inhibiting clays and cuttings because they isolate the aqueous phase and induce changes to the wetting characteristics of reactive clays and gumbo. The surfactants used in OBM preferentially "oil-wet" surfaces and impart a hydrophobic character to the formation and cuttings.

Clay and cuttings inhibition is more difficult to achieve with conventional WBM because of the similarity in wetting characteristics between the base fluid and formation. Lack of inhibition is mainly caused by the continual presence of free water that affects the water sensitive shale structure. The clay hydration suppressant in the HPWBM stabilizes the water sensitive shale structure through a mechanism of cation exchange, inhibiting the water sensitive shale from hydrating.

FLUIDS DESIGN

Shale instability is a critical issue for drilling. Consequently, it is important to design selective customized drilling fluids. The key success factors to prevent wellbore instability include fluid designs in line with chemical inhibition to reactive shale. Customized drilling fluids consider shale inhibition, pore pressure transmission, reduction of torque and drag, cutting integrity, and ROP.

The objective of a customized drilling fluid design using a sealing polymer and bridging material is to strengthen the wellbore and improve wellbore stability. A sealing polymer with an aluminum and resin-based complex is used to generate a semi-permeable membrane for shale stabilization.

A high molecular weight, partially hydrolyzed polyacrylamide (PHPA), is used in a customized fluid as a shale stabilizer for cutting encapsulation and improving cutting integrity. Polyamine provides superior inhibition of reactive clays and gumbo by suppressing hydration and swelling within the clay mineral's platelets. This customized drilling fluids system was designed for different intervals, taking the following objectives in consideration:

- Improving hole stability through reactive formations.
- Enhancing hole cleaning efficiency at critical angles.
- Minimizing the risk of stuck pipe across depleted formations with high porosity and permeability.
- Minimizing or having no induced losses while drilling, utilizing the unique wellbore strengthening technique.
- Improving ROP to optimize drilling efficiency.

LABORATORY CUSTOMIZATION FOR HPWBM

It is important to understand formation mineralogy when designing drilling fluids. Shale analysis and rheological and inhibition efficiency analysis were performed on field shale samples with different types of polymer-based fluids.

The tests performed to identify the best drilling fluid included:

- X-ray diffraction (XRD) analysis
- Scanning electron microscope (SEM) analysis
- Cation exchange capacity (CEC) test
- Fluid stability test
- Lubricity measurement test
- Shale dispersion test
- Capillary suction timer (CST) test
- Linear swell meter test

XRD Analysis

The mineralogical composition of the samples was analyzed using an X-ray diffractometer. This is a semi-quantitative method of analysis; quantification can only be within an error margin of ±5%. This analysis works on the principle that all minerals and clays are crystalline to some degree, e.g., quartz is crystalline and clays are poorly crystalline with less sharp peaks.

By using XRD analysis, the mineralogy of the cuttings and cores from a relatively small sample can be determined. Finely ground samples are bombarded by X-rays, and the resulting

Mineral Phase	Weight %
Kaolinite	90.7
Quartz	9.3

Table 1. XRD results of the shale area to be drilled

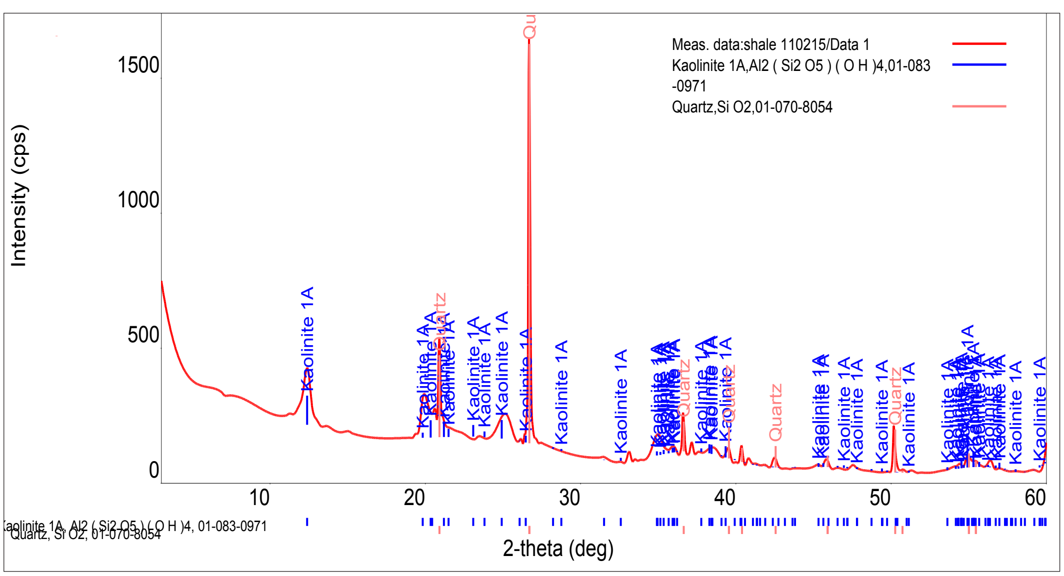


Fig. 1. XRD spectrum showing the spikes of the shale sample.

reflections are measured. This provides the mineral phase of the sample. Common clay types include smectite, kaolinite, illite, and chlorite. Table 1 shows the XRD analysis results of the section planned to drill. Figure 1 shows the spectrum of the sample from the XRD analysis.

Based on the results from the XRD, it clearly shows approximately 90% of the sample tested is kaolinite. Kaolinite is often associated with shale dispersion.

SEM Analysis

A SEM and energy dispersive X-ray spectroscopy (EDS) analysis were performed on the powdered sample to determine the elemental compositions of shale at the microscopic level. The SEM analysis shows the morphology of the sample, whereas EDS is a semi-quantitative elemental analysis that makes use of the X-rays generated from the interaction between the electron beam and the electrons present in the elements in the sample. The major elements present in the clay sample were aluminum, silicon, and oxygen. These elements confirm the kaolinite clay as presented in Table 2, and Fig. 2 shows the output of the EDS spectrum analysis.

CEC Test

The CEC test measures the exchangeable cations present in the shale sample. These cations — positively charged atoms — of the clay, are easily replaced with other positively charged species. This phenomenon is driven by the fact that the original cations are not as compatible to the negatively charged site as the newly introduced positively charged species. Consequently, the exchangeability of the cations is directly related to the reactivity of the shale. Typically, sodium, potassium, magnesium, calcium, and iron are exchangeable ions.

The CEC test represents as a milliequivalent per gram of clay (mEq/100). Normally, the oil and gas industry measures the CEC with an API recommended methylene blue capacity test. A higher CEC result represents the increased reactivity of shale. Results shown in Table 3 confirms the clay is highly reactive. Generally, a result > 20 mEq/100 is considered as a reactive shale.

Fluid Stability Test

Six different fluids were tested after several attempts to optimize the parameters for rheological properties before performing the shale analysis. Table 4 is a list of the customized HPWBM properties that best suited all parameters, before and after being hot rolled at 200 °F. Table 5 lists the conventional WBM properties before and after being hot rolled at 200 °F.

Lubricity Measurement

The lubricity meter measures the coefficient of friction between two solids in a fluid. For the standard lubricity coefficient test, 150 pounds of force — the equivalent of 5,000 to 10,000 psi pressure on the intermediate fluid — is applied between two hardened steel surfaces, a block, and a ring rotating at 60 rotations per minute.

A total of six drilling fluids were tested for the lubricity coefficient, Table 6. Based on the test results, both the HPWBM-I and HPWBM-II show better lubricity compared to other conventional mud systems.

Shale Dispersion Test

Shale dispersion testing is performed to determine cuttings recovery. A pre-weighed sample of shale is placed in an aging cell containing a laboratory barrel (350 ml) of drilling fluids. The aging cell is pressurized and sealed. The test muds are hot rolled at 200 °F for 16 hours and screened through an 8 mm

Element	Weight %	Atomic %
Oxygen	36.24	52.23
Silicon	26.74	21.95
Aluminum	18.3	15.64
Iron	8.26	3.41
Titanium	1.24	0.6
Calcium	1.58	0.91
Potassium	3.86	2.27
Sulfur	2.73	1.96
Sodium	0.39	0.39
Magnesium	0.67	0.63
Total	100	100

Table 2. Results of the SEM and EDS analysis showing the mineral quantification of the shale samples

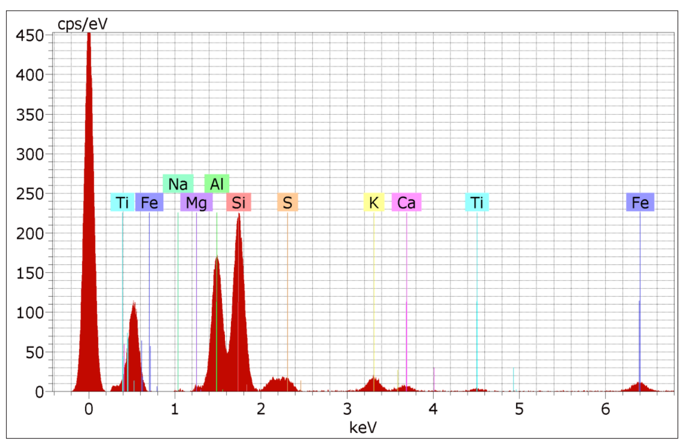


Fig. 2. EDS spectrum of the shale sample.

CEC (mEq/100 g)	Reactivity
26	High

Table 3. CEC test results of the shale sample

Product	Units	HPWBM-I	HPWBM-II
Water	lb/bbl	311.32	290.68
Soda Ash	Ib/bbl	0.25	0.25
Caustic Soda	Ib/bbl	1	1
Sodium Chloride	Ib/bbl	—	25.77
Viscosifier	Ib/bbl	1.25	1.25
Fluid Loss Additive	Ib/bbl	5	5
PHPA	Ib/bbl	1.5	1.5
Aluminum Complex	Ib/bbl	4	4
Sealing Polymer	Ib/bbl	11.04	11.04
Anti-acreetion Agent	Ib/bbl	2.92	2.92
Polyamine	Ib/bbl	11.88	11.88
Loss Circulation Material	Ib/bbl	5	5
Bridging Material (fine)	Ib/bbl	25	25
Bridging Material (medium)	Ib/bbl	5	5
Weighting Material	Ib/bbl	54	29.96
Initial Properties			
Mud Weight	ppg	10	10
pH	—	10.9	10.8
600/300	Dial Reading (DR)	64/46	67/46
200/100	DR	37/26	37/27
6/3	DR	8/6	8/6
Plastic Viscosity	cP	18	21
Yield Point	lb/100 ft^2	28	25
Gel 10 sec/10 min	lb/100 ft^2	6/8	6/7
Properties after hot rolling at 200 °F for 16 hours			
pH	—	10.6	10.52
600/300	DR	70/50	65/46
200/100	DR	40/28	46/37
6/3	DR	9/8	10/8
Plastic Viscosity	cP	20	19
Yield Point	lb/100 ft^2	30	27
Gel 10 sec/10 min	lb/100 ft^2	7/9	7/9
API Fluid Loss (mL)	mL	3.2	2.7
HPHT at 200 °F	mL	7.6	5.4

Table 4. Customized HPWBM properties before and after being hot rolled at 200 °F

mesh. The solids retained on the 4 mm mesh are washed, dried, and weighed. The moisture content of the shale samples is determined and considered in erosion calculations as shown in Eqns. 1 and 2.

$$\text{Moisture \%} = \frac{Initial\ Weight\ (gms) - Dry\ Weight\ (gms)}{Initial\ Weight\ (gms)} \times 100 \quad (1)$$

$$\text{Recovery \%} = \frac{Final\ Dry\ Weight\ (gms)}{Initial\ Dry\ Weight\ (gms)} \times 100 \quad (2)$$

The dispersion of shale is problematic while drilling, and this can be caused by various clays, such as illite and kaolinite, within the shale samples. The major consideration of customized HPWBM drilling fluids is to prevent these minerals from dispersing, and to enhance cutting integrity so they can be separated out by the shale shakers. The shale dispersion tests were performed on core samples using designed fluids following these steps to evaluate fluid performance, and are reported in Table 7. The HPWBM samples clearly shows less dispersion compared to the other conventional mud systems.

Product	Units	KCl Polymer	KCl/PHPA/ Glycol Polymer	NaCl Polymer	NaCl/PHPA/ Glycol Polymer
Water	lb/bbl	315.76	303.03	311.08	300.01
Soda Ash	lb/bbl	0.25	0.25	0.25	0.25
Caustic Soda	lb/bbl	1	0.3	0.3	0.3
KCl	lb/bbl	23.77	17.07	—	—
NaCl	lb/bbl	—	—	54.9	56.7
Viscosifier	lb/bbl	1.5	1.25	1.5	1.25
Starch	lb/bbl	5	5	5	5
APC	lb/bbl	1.5	1.5	1.5	1.5
Loss Circulation Material	lb/bbl	5	5	5	5
PHPA	lb/bbl	—	1.2	—	1.2
Bridging Material (fine)	lb/bbl	25	25	25	25
Bridging Material (medium)	lb/bbl	5	5	5	5
Glycol	lb/bbl	—	10.65	-	10.65
Weighting Material	lb/bbl	36.72	44.29	10.28	7.68
Initial Properties					
Mud Weight	ppg	10	10	10	10
pH	—	11.5	11.3	10.8	10.2
600/300	DR	53/36	66/48	47/32	62/42
200/100	DR	28/20	36/24	25/17	34/23
6/3	DR	6/5	5/4	4/3	4/6
Plastic Viscosity	cP	17	18	15	20
Yield Point	lb/100 ft^2	19	30	17	22
Gel 10 sec/10 min	lb/100 ft^2	5/6	4/4	3/4	5/6
Properties After Hot Rolling at 200 °F for 16 Hours					
pH	—	9.6	9.5	9.5	9.4
600/300	DR	49/34	53/39	41/29	62/44
200/100	DR	26/19	30/21	24/16	36/25
6/3	DR	6/4	6/5	3/2	6/5
Plastic Viscosity	cP	15	14	12	18
Yield Point	lb/100 ft^2	19	25	17	26
Gel 10 sec/10 min	lb/100 ft^2	4/4	5/5	2/3	5/6
API Fluid Loss (mL)	mL	3.5	3.7	3.4	2.7
HPHT at 200 °F	mL	20.4	10	11.8	23

Table 5. Conventional WBM properties before and after being hot rolled at 200 °F

Fluid System	Lubricity Coefficient
HPWBM-I	0.1921
HPWBM-II	0.1971
KCl Polymer	0.2025
KCl/PHPA/Glycol Polymer	0.2143
NaCl Polymer	0.1994
NaCl/PHPA/Glycol Polymer	0.2523

Table 6. The lubricity coefficient of six tested drilling fluids

CST Test

The CST test measures the time of movement of a waterfront between two electrodes, which is related to the ability of the fluid to flocculate or disperse clays in a sample. When comparing multiple samples in the same fluid, the longer the time of waterfront movement, the greater the water sensitivity of the sample — the greater the dispersion. The CST test was run using filtrates of the designed fluids system and is measured in seconds. Table 8 shows the test results of both HPWBM

Fluid Formulation	Initial Weight (gm)	Initial Dry Weight (gm)	Moisture (%)	Final Dry Weight (gm)	Recovery (%)
HPWBM-I	20	19.71	1.45	19.21	97.46
HPWBM-II	20	19.75	1.25	19.59	99.18
KCl Polymer	20	19.00	5.0	17.51	92.16
KCl/PHPA/Glycol Polymer	20	19.22	3.9	17.96	93.44
NaCl Polymer	20	19.02	4.9	18.12	95.27
NaCl/PHPA/Glycol Polymer	20	19.24	3.8	18.3	95.11

Table 7. Dispersion test results of the selected fluids

Type of Fluids	CST #1 (sec)	CST #2 (sec)	Average (sec)
HPWBM-I	176.3	185.2	180.75
HPWBM-II	186.2	172.1	179.15
KCl Polymer	69.8	71.3	70.55
KCl/PHPA Polymer	92.3	72.3	82.3
NaCl Polymer	97.9	85.2	91.55
NaCl/PHPA Polymer	146.6	133.9	140.25
Water	105.3	90.3	97.8

Table 8. CST test results on different fluids

samples responded better when compared to conventional WBMs.

Linear Swell Meter Test

The linear swell meter apparatus is used to determine shale hydration or dehydration by measuring the increase or decrease in length over time of a reconstituted or intact shale core, respectively. Formation clays are hydrated when in contact with drilling fluids if it is not inhibitive.

The test is conducted using finely ground powder that is subjected to a compactor. The compactor applies a 10,000 psi pressure for more than 2 hours to a compact pallet with drilling fluids. The swelling measurement is collected by a linear transducer on top, and volumetric changes are recorded by a transducer and determined as a swelling percentage. The formulated fluids were tested and reported in Table 9. Samples in HPWBM shows less swelling compared to conventional mud systems, indicating the recommended mud system provides better inhibition.

Type of Fluids	Swelling %
HPWBM - I	15.64
HPWBM - II	15.64
KCl Polymer	19.12
KCl/PHPA Polymer	20.25
NaCl Polymer	17.15
NaCl/PHPA Polymer	18.25

Table 9. Linear swell meter test results on the shale samples using different fluid systems

FIELD APPLICATION

It was planned to drill a well with a 12.25" section and with 9.4 pounds per gallon (ppg) WBM, increasing the mud weight gradually, depending on the hole's condition. The main concerns during drilling this section are loss circulation and the unstable shale in this formation. A HPWBM was chosen after

Properties	Units	12.25"
Density	ppg	9.4 - 9.5
Funnel Viscosity	sec/quart	55 - 58
Plastic Viscosity	cP	15 - 18
Yield Point	lb/100 ft^2	22 - 28
API	mL/30 min	3.2 - 3.8
HPHT at 200 °F/500 psi	mL/30 min	10 - 12
pH	—	10.5 - 18.9
Hardness	mg/L	250 - 300
Chlorides	mg/L	80,000

Table 10. Mud properties used and parameter ranges maintained during drilling

reviewing the benefits and laboratory test results when compared to conventional salt polymer muds. These factors contributed to the decision to use a HPWBM to drill this interval.

CHALLENGES

There were several challenges faced in drilling the sample well, including the need to provide wellbore stability in highly reactive shale formations; the potential risk of induced losses; and the hole becoming tight, due to reactive shale.

The recipe for the HPWBM-II sample shown in Table 4 was used, and all properties tightly controlled. Table 10 shows the mud properties used and parameter ranges maintained during drilling.

CONCLUSIONS

The well was successfully drilled to total depth without any nonproductive time related to drilling fluid or hole cleaning. The hole was in good shape, and the cuttings were observed as discrete, indicating excellent inhibition. A 9⅝" casing was run all the way to the bottom without any issues, indicating a gauge hole with minimal washout. The designed HPWBM system proved its superiority and efficiency compared to the fluid used in the previous wells. The next two wells were also drilled successfully in the same field with the same HPWBM system, further proving its utility and performance.

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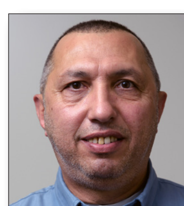
BIOGRAPHIES

Rafael M. Pino Rojas joined Saudi Aramco in June 2013 as a Drilling Engineer working in the Drilling Operations Support Unit of the Drilling Technical Department. He has over 15 years of experience in technical and operational procedures, including coordination and supervision of onshore operations in Venezuela and offshore operations in Saudi Arabia. Rafael was trained as a Drilling and Completion Fluids Engineer and has advanced knowledge in the design and field application of oil-based drilling fluid systems (invert emulsion, 100% oil) and water-based systems (conventional, high performance and drill-in), as well as the elaboration of drilling fluids techno-economic proposals under different contract schemes.

Prior to joining the company, he worked for Baker Hughes for 13 years.

Rafael received his B.S. degree in Chemical Engineering from the Universidad Central de Venezuela, Caracas, Venezuela.



Ihab M. El-Habrouk joined Saudi Aramco in July 2014 as a Drilling Fluid Specialist working in the Drilling Operations Support Unit of the Drilling Technical Department. He has over 24 years of oil field experience in technical and operational procedures, including project engineering management of onshore and offshore operations in different countries. Ihab was trained as a Drilling and Completion Fluids Engineer and has advanced knowledge in the design and field application of different types of oil-based and water-based drilling fluids systems.

He has a filed patent, and is a member of the Society of Petroleum Engineers (SPE).

Ihab received his B.S. degree in Mechanical Engineering from Alexandria University, Alexandria, Egypt.

Ajay Kumar V. Addagalla is currently working as the Technical Manager for Drilling and Completion at Baker Hughes, a GE company for the Saudi Arabia and Bahrain Geomarket. He has more than 9 years of oil field experience and has served in various positions in Engineering, Operations and Sales. Ajay's areas of expertise include drill-in fluids, completion fluids and near wellbore damage remediation techniques.

He received his B.Tech. degree in Chemical Engineering from Jawaharlal Nehru Technological University, Hyderabad, India, and his M.S. degree in Petroleum and Environmental Engineering from University of Nottingham, Nottin gham, U.K.

Prakash B. Jadhav is currently working as an Operations Manager at Baker Hughes, a GE company, in the Drilling and Completions fluids product line for the Saudi Arabia and Bahrain Geomarket. He has more than 15 years of experience in the oil industry, and has executed critical high-pressure, high temperature, extended reach drilling and deepwater well campaigns with major operators and worked in more than five countries. Prakash has served in various positions in Operations and Sales before coming to Saudi Arabia in his current position.

He received his B.Tech. degree in Chemical Engineering from Dr. Babasaheb Ambedkar Technological University, Lonere, India.