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Multistage Horizontal Well Hydraulic Fracturing Stimulation Using Coiled Tubing to Produce Marginal Reserves from Brownfield: Case Histories and Lessons Learned

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Abstract

The Baharyia formation is a common reservoir in the Western Desert of Egypt. It is characterized as a heterogeneous reservoir with low sand quality. It is comprised of fine-grained sandstone, thin, laminated, sand-poor parasequences with shale interbeds. The heterogeneity and low permeability of the Upper Baharyia reservoirs are the primary challenges to maintaining economic well productivity.

The interest in developing low permeability reservoirs stems from favorable economics attributed to advancements in horizontal well drilling and hydraulic fracturing technology, offering methods to increase production by increasing the contact area of the producing interval. Subsequently, it became apparent that wellbore contact alone was not always sufficient for providing production increases expected, thus requiring multistage hydraulic fracturing (MSHF) stimulation treatments to achieve production targets.

Primary well production analysis revealed that the cumulative production from the horizontal well discussed was enhanced from 37 to 70% of recoverable reserve and the recovery factor was doubled. From a production analogy standpoint, these resulted in reduced drilling of three vertical wells and had direct economic benefits by reducing the installed artificial lift strings, related expensive artificial lift equipment repairs, and the number of necessary workovers.

This paper takes a multidisciplinary approach to help understand productivity enhancement of low permeability reservoirs in the Western Desert of Egypt, through a detailed analysis of well performance and successful implementation of MSHF in horizontal wells to maximize drainage volume around the well. It is intended to serve as guidelines to help operators facing similar challenges.

Geology of Baharyia Formation

Umbarka and Khalda Oil Fields. The Umbarka and Khalda oil fields (the two fields of the case histories discussed) lie in the north Western Desert Province, which encompasses a number of prolific sedimentary basins (e.g., Matruh, Shushan, Alamein, Natrun, Hayat West, Nader and Shrouk East) and hydrocarbon producing fields in Egypt. These are located approximately 480 km west of Cairo and approximately 70 km south of the Mediterranean coast. The prominent basins in the area are filled with a thick sedimentary cover approximately 14,000 ft thick and range in age from Paleozoic to recent **(Fig. 1).** They are punctuated by several unconformity and erosional surfaces with the principal source-and reservoir-rock intervals hosted primarily in the Jurassic-Cretaceous succession **(Fig. 2).**

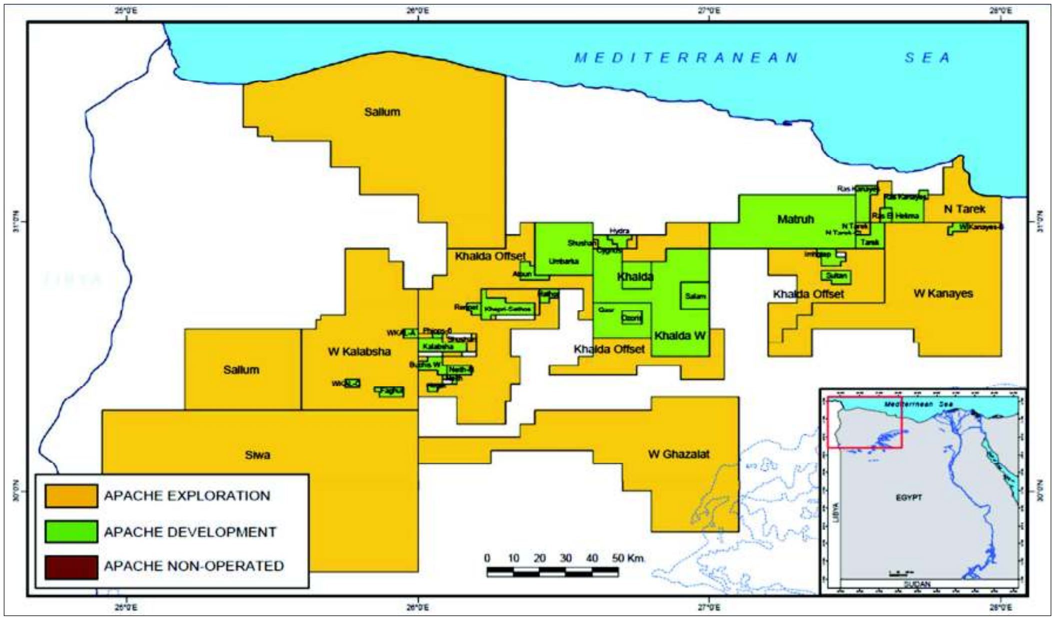

Fig. 1—Location map of Khalda and Umbarka fields.

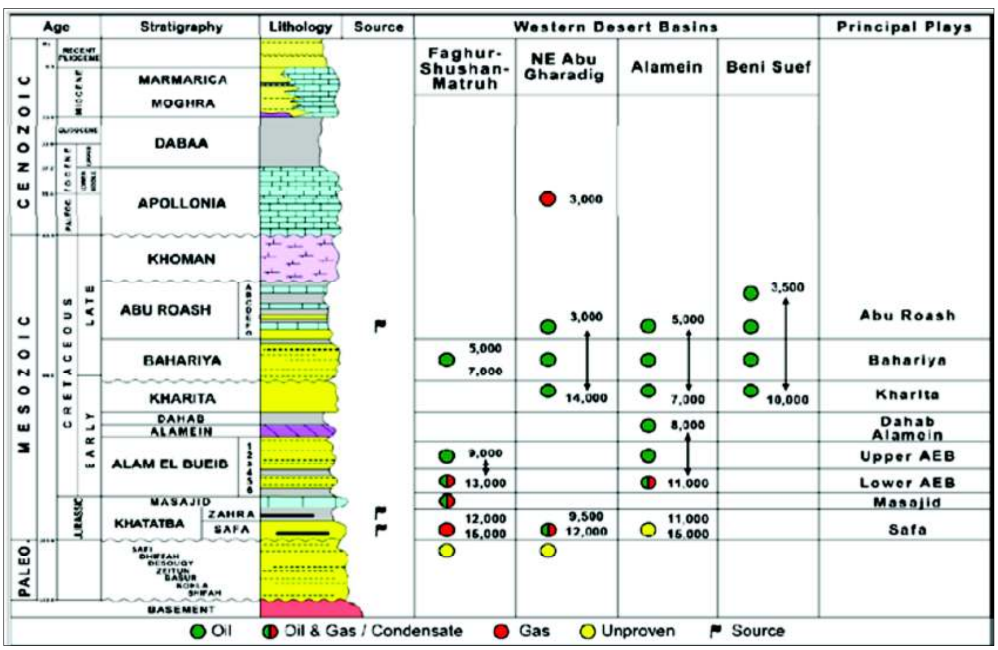

Fig. 2—Generalized stratigraphic succession of north Western Desert, Egypt.

The Lower Cenomanian clastic succession of the Bahariya formation is one of the primary targets for hydrocarbon exploration and production in the north Western Desert (El Ayouty 1990). The sequence encompasses, in the upper half, several hydrocarbon bearing sandstone bodies sealed within impermeable mudstone units. Those sandstone reservoirs are very erratic in terms of thickness and distribution. Their lateral prediction is one of the difficult tasks facing sedimentologists and explorationists. Such erratic occurrence is almost inherited or related to the depositional pattern of the Bahariya clastics. The latter were developed along a wide marginal marine setting with various adjacent subenvironments that were currently shifted and overlapped in response to the Cenomanian relative sea level changes. These types of stranded **(Fig. 3)** Upper Bahariya reserves occur throughout the operator's concession areas and are not economically viable with vertical wells.

The Upper Baharyia formation has poor reservoir permeability ranging between 2 and 5 md. The porosity can be between 16 and 20% with water saturation of 40 to 50% and an average net pay of 100 to 134 ft. Though the reservoir thickness and extent can be erratic, the Upper Bahariya forms a reasonable reservoir size spread over several hundred km^2 (refer to Fig. 3, examples of stranded Bahariya reserves, which goes beyond the referenced Khalda and Umbarka fields).

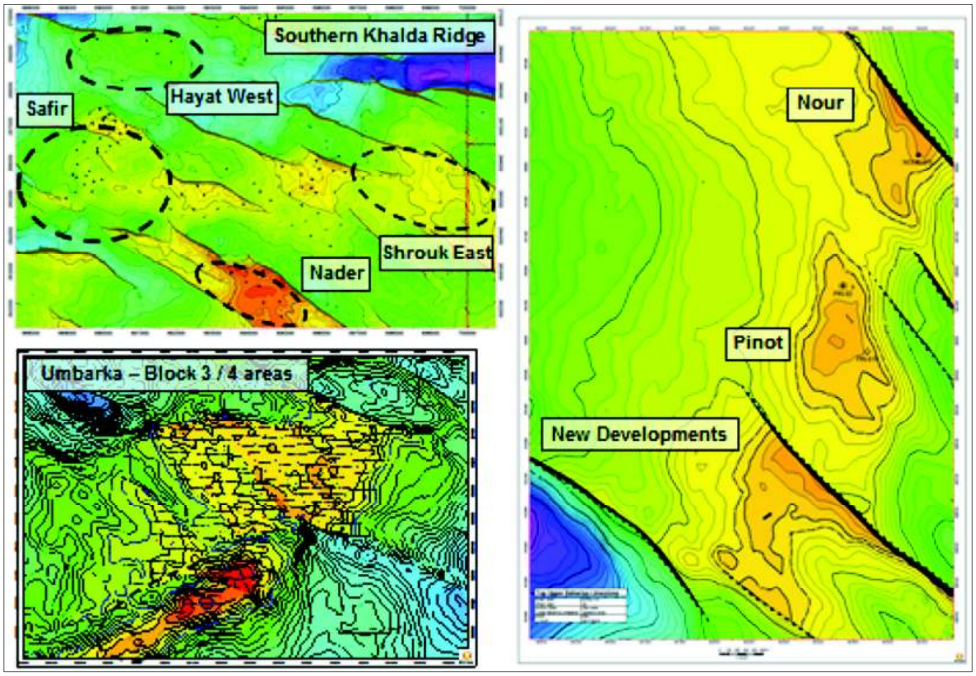

Fig. 3—Upper Bahariya stranded reserves.

Economics of Upper Bahariya Development

The Upper Bahariya (UBAH) development began in 1998 through 2003 time period in the Khalda and the Umbaraka Block 3 areas. Production from the two fields was less than 500 BOPD from more than 30 vertical wells combined. It was found that approximately half of the vertical UBAH wells in Khalda were uneconomic with an economic estimated ultimate recovery (EUR) limit of 40 MSTB, while in Block 3 indicated that the average EUR was 80 MSTB/well and the total EUR by decline curve analysis (DCA) was 0.73 MSTB. The recovery factor was less than 9% based on the existing UBAH production data. Having more than 48% of the proven reserves undeveloped required a concerted effort to help improve economics and recovery.

A case for horizontal well drilling was made. It was simulated that a single horizontal well with approximately 3,000 ft lateral could replace three vertical wells in terms of production and ultimate recovery. The productivity of the horizontal is better than the vertical because of the large productive area and the dense development represented in multistage fracturing treatments. The chances of missing the sand were also low compared to the vertical wells (two vertical wells are necessary to develop the same area).

An economic analysis suggested that typical expenditures for drilling and completing such a well would cost approximately USD seven million with a significantly positive net present value (NPV) and a payback time of three months, assuming 10% discount and $100/bbl oil price.

Methodology for Developing Uneconomic Reserve and Enhancing Productivity

The methodology used for choosing the drilling locations and drilling the horizontal wells involved intense screening. As an example involving one of these wells is discussed next.

A pilot horizontal well, Well KH-X1, was drilled targeting the Upper Baharyia-100 sand near the northwest flank of Khalda field. The original objective of this project was to drill approximately 3,000 ft horizontally, test productivity, and follow up with four to five fracture stimulation stages to connect the thin sand interbeds to achieve higher productivity. This was an unconventional approach for developing the Upper Baharyia formation. The choice of the Khalda field as a starting field for such unconventional drilling and completion operations in the Upper Baharyia of the Western Desert area was made for multiple technical reasons:

- Excellent understanding of lateral and vertical reservoir distribution; an estimated 98% of the reserve is concentrated in a 100-ft thick zone. This thickness can be easily connected through transversal fracturing.

- Fracture modeling studies indicated considerable pay sections would be stimulated.
- Good depth control from offset wells.
- High-quality seismic data through sections of interest.
- Consistent formation thicknesses and numerous markers to aid geosteering.

The first step in choosing the location was to identify an area analogous to the area of the proposed horizontal well in terms of average recovery factor and drainage area. The southwest corner of the Khalda **(Fig. 4),** being on the flank, had only primary production, and a reasonable development density with vertical wells. This provided a reasonable economic figure for production and recovery factors, which could be used to justify drilling a horizontal well.

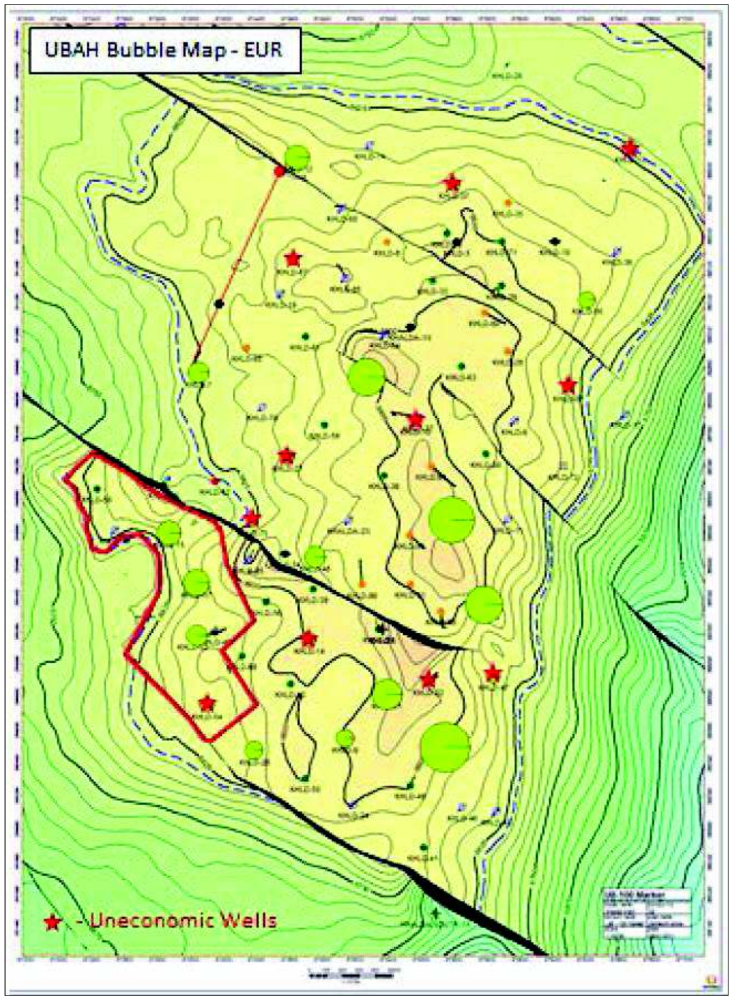

Fig. 4—Upper Bahariya-Khalda field bubble map.

The pre-well model created for the well was based on multiple offset wells around the proposed well plan where good logging data and seismic grid surfaces were available. High-quality seismic data over the proposed location with consistent velocity across the structure and an unfaulted section with relatively minor dip changes along lateral length was selected for drilling the well **(Fig. 5).** There were six wells within 500 m of the horizontal section to provide depth control.

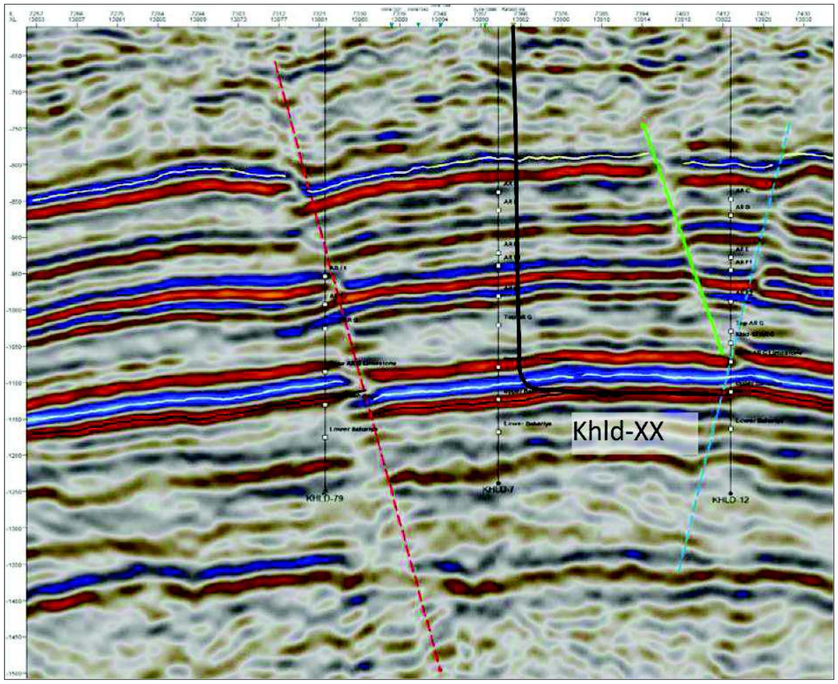

Fig. 5—Seismic data and well control for drilling the horizontal well.

However, with all the positive properties of the field, some important and critical challenges were to be considered when placing a horizontal well in such a formation. These challenges included:

- Thin reservoir nature.
- Low resistivity contrast can affect the logging while drilling (LWD) depth of investigation response while geosteering.
- Uncertainties of dips and faults.

The target was to develop an uneconomic reserve by maximizing reservoir contact and significantly enhancing productivity through multistage hydraulic fracturing. The well was chartered to:

- Drill approximately 3,000 ft laterally horizontal after reaching target (~ 6,500 ft vertical).
- Drill the horizontal section in the good reservoir quality and remain in there.
- Connect the stacked layers vertically by placing four to five multistage transverse fracturing treatments.
- Improve stage fracturing by ensuring zonal isolation was achieved in the horizontal section by running a cemented liner.

Design Process and Optimization of Fracturing Treatments

Many forms of multizone fracturing techniques have been used within the industry for many decades. Operators have been isolating zones in vertical wells with bridge plugs or other forms of barriers while hydraulically fracturing prospective zones sequentially going up the hole. The same process has been extended to horizontal wells using similar isolation techniques, and with the development of special downhole completion equipment allowing selectivity and isolation. The operator was aware of such developments, but the time necessary to order and receive completion equipment was long and did not provide flexibility in terms of completion design should the hole size change because of unanticipated hole problems while drilling. With these limitations in mind, a hydrajet perforating and annular-path pumping (HPAP) process was considered for multistage fracturing.

The HPAP process conducts fracture stimulation using coiled tubing (CT) hydrajetting, followed by (1) annular-path pumping of the fracturing treatment and (2) use of high-concentration proppant slugs to create proppant plugs for diversion. The process of hydrajet perforating and HPAP has been used effectively for vertical and horizontal well completions and is especially applicable for multi-interval completions.

HPAP With Proppant Plug Diversion. Using CT, hydrajet perforating, annular path treatment placement, and proppant plugs for diversion **(Fig. 6),** the HPAP with proppant-plug diversion (PPD) method was introduced to the industry in 2004 (East et al. 2008; Surjaatmadja et al. 2005; McDaniel 2005, Hejl et al. 2006). The method overcame the need for monobore completions because there were no mechanical devices to set inside the casing. A well completed with either just a casing string or with a lower liner through the pay interval can easily be treated using this method. A simple bottomhole assembly (BHA) containing a hydrajetting device, a ball check, a shear sub, and a CT connector was all that was necessary **(Fig. 7).** By removing the packer component, the BHA could be pulled uphole and away from the perforation location before the sand-laden frac slurry reaches bottom. This feature immediately allowed more aggressive proppant concentrations throughout the fracturing stage.

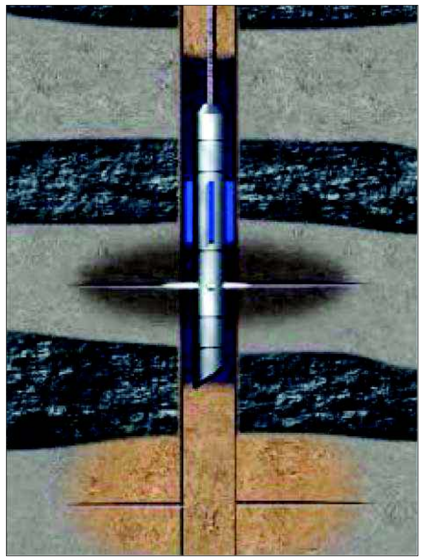

Fig. 6—The HPAP fracturing treatment with proppant plug diversion is illustrated for a vertical well completion. The method uses a simple BHA most often conveyed with conventional sized CT.

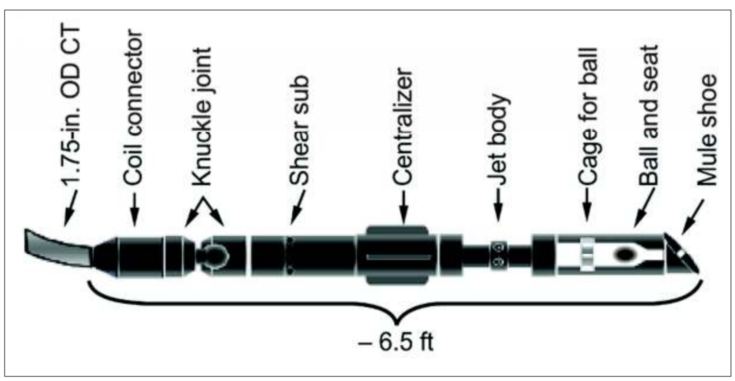

Fig. 7—The HPAP with PPD method BHA can be deployed in vertical wells or horizontal laterals. An alternative assembly would eliminate the muleshoe collar, lower ball sub, ball, and cage to be replaced with a downward-facing jet sub. That arrangement would enable easier washouts up the annulus and resuspension of settled proppant, but sacrifice recirculation up the CT string.

Cased and cemented horizontal completions present several challenges to the HPAP method, including (1) unique CT calculations and operating procedures and (2) proppant plug-setting procedures. The HPAP stimulation method was first introduced to applications in horizontal completions in 2005 (McDaniel et al. 2006). Thompson et al. 2009 discusses overcoming some of the proppant plug-setting in early wells in the Big Horn basin of BC, Canada. This multistage completion process can also be applied in other methods of horizontal completions that incorporate a solid liner.

CT Calculations. Although the HPAP with the PPD method can be performed using jointed tubing and hydraulic workover equipment (HWE), the most common deployment method for the hydrajetting BHA is CT. Routine pipe management calculations, such as cycle life and force calculations, are typically performed for most CT well intervention operations, but some calculations are unique to the HPAP process.

CT Collapse. High friction pressures associated with HPAP can increase the collapse conditions during the fracturing process. Typically, the BHA has only a downward ball-seat valve (caged, but free to move upward) installed and the CT string can be used as a live dead string to monitor bottomhole pressure. The hydrostatic pressure differences of the fluids in the CT and annulus are transferred to the CT inside diameter, but friction from high flow rates in the annulus are not transferred and a significant differential can exist. Pumping simulations should be conducted to calculate the expected collapse pressure to help ensure that the CT has the properties to resist collapse conditions present during the job. Because tensile load is a part of the collapse function, force calculations should be conducted and should include the axial load from the buoyant pipe weight and axial load from fluid drag against the CT in the annulus. It is a common practice to continuously pump slowly down the CT string while pumping the frac fluids down the annulus, both to keep the string clean and to help protect it from collapse.

(Note that, for sour well applications, a check valve is a normal requirement. In processes that require reverse circulation, the check valves are removed and additional shear/seals are added in the well-control stack to maintain barrier requirements.)

CT Lockup in Horizontal Laterals

CT under axial compression can buckle into a helix if the compressive force exceeds a certain value. This buckling significantly increases the drag between the CT and wellbore. As the length of the buckled section increases, a point is reached where the downhole end of the CT stops moving, although there is still pipe movement at surface. This point is known as “lockup” and any further attempt to move pipe into the well could cause damage to the CT.

Force calculations can predict the depth of lockup or the point where the required set-down force to manipulate a packer cannot be transferred to the BHA. Force calculations should be completed to help ensure that the target depth can be reached in horizontal or deviated wells. If the calculations indicate it could be difficult to place the CT to desired depth, there are two common methods used to improve the situation. The first is lubricant fluids (as used in drilling) circulated into at least the horizontal part of the wellbore and up the bend and the other is the use of nitrogen to lighten the fluid inside the CT, which can also reduce horizontal drag.

CT Depth Correlation

In CT service operations, the current process for depth determination is a counter wheel placed so that it contacts either the CT itself or the injector chains that deploy the CT. In most cases, the signal from the counter wheel is converted by an encoder and then processed by software to compensate for stretch and slippage. Use of CT can be an accurate method of measuring vertical component depth, although this statement can seem self-contradictory to some because of a history of chronic depth correlation problems experienced with use of CT. CT has stretch and temperature properties similar to those associated with slickline. The increased cross-sectional area of CT and load capacity reduce the chances of exceeding the yield point of the material, which, in most cases, keeps the properties more consistent than slickline properties. Slickline is typically operated at the top ends of its limits. The change from accurate to inconsistent occurs when outside forces are introduced, such as well dynamics and pressure cycling. Elements that drive the requirement to perform CT depth correlation are listed and described next:

- Counter wheel dimensions—The wheel that contacts the tubing should have a circumference that matches the calibration of the readout equipment.
- Counter wheel slippage—Tensioning devices on the wheel should supply the required contact force to help prevent slippage of the wheel on the tubing.
- Proper fleet angle—The tubing should enter and exit the counter assembly in a straight manner.
- Elongation from plastic strain cycling—As the CT is cycled on and off the reel, the length increases from applied reel tension and plastic deformation. Studies are currently in progress to determine the amount of length increase incurred in specific conditions. This length change is permanent and can be as much as 20 ft, given the correct conditions.
- Elongation from elastic axial loading—The axial load increases on the hanging portion of the CT string; the length increases/decreases proportionately to the load applied.
- Elongation from temperature change—As the temperature of the CT increases, the length increases in proportion to the delta temperature change.
- Shortening from temperature change—High-rate pumping can cool the CT and cause a depth change during operations.
- Well conditions—Different well conditions from the time the baseline depth correlation is recorded to the time that CT is run in the well is the most overlooked source of incorrect depths.
- Shortening can be caused by applied pressure.

All of the discussed factors require downhole depth correlation and corrections to be made to account for pipe length change during the fracturing treatment

Real-Time Force Modeling

Advanced force monitoring and real-time fatigue models are critical to providing the CT operator the information necessary to maintain safety margins during HPAP operations. Advanced real-time software continuously calculates tubing stress, cycle fatigue, fluid positions, and downhole hydraulic conditions from real-time sensor data. This gives the operator a dynamic operating envelope that is continuously updated as conditions change. Comparing real-time calculations to output from job design modeling software and other advanced features allows for comprehensive decision making during the intervention. The capability to transmit sensor data and calculated parameters by means of satellite or internet allows office-based personnel globally to monitor operations based on complete, most recent information. **Fig. 8** shows an example output of real-time force modeling.

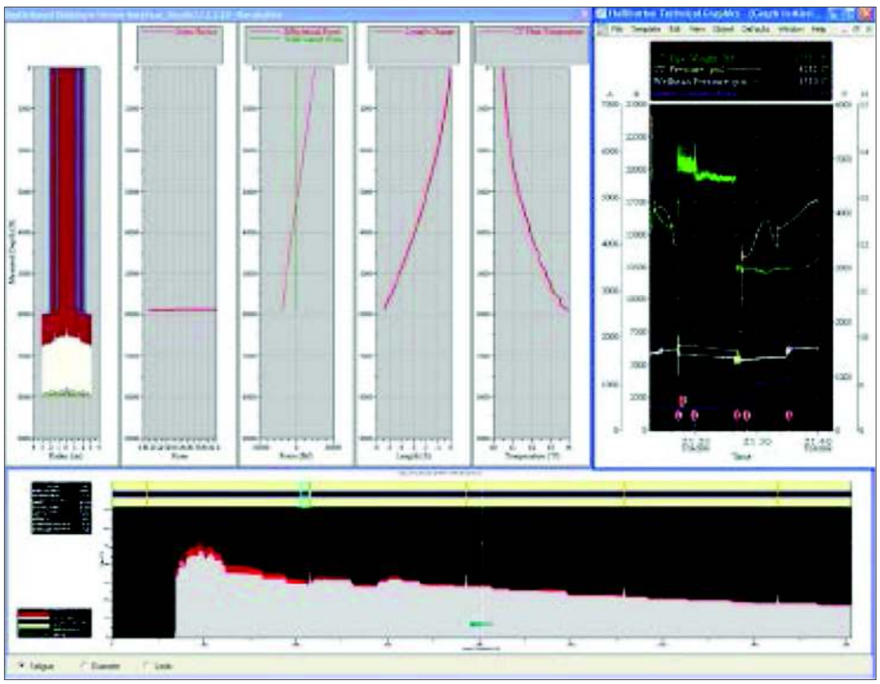

Fig. 8—Example of real-time force modeling.

Hydrajet Perforating and Fracture Initiation

Hydrajet perforating offers many distinct advantages compared to conventional explosive-jet perforating, particularly when fracture stimulation is necessary. For instance, explosive-shape-charge perforating can produce a low-permeability, compacted (stressed) region around the perforation tunnels that can result in near-wellbore (NWB) tortuosity during fracture stimulation (Surjaatmadja et al. 1994; Van Gitjenbeek et al. 2004; Pongratz et al. 2007). In this case, the fracture will most often initiate at the cement/formation interface and travel around the compacted perforation tunnel region. The degree to which such problems exist with conventional explosive perforating appears to be a function of rock hardness, where problems become more common and more severe as formation hardness increases (Pongratz et al. 2007; McDaniel 2005; McDaniel 2007, McDaniel et al. 2008).

Hydrajet perforating uses an erosion process to remove rock, thus no compaction damage exists in the resultant eroded tunnel in the rock. The fracture can initiate from an undamaged, uncompacted, and larger diameter perforation tunnel. If formation breakdown is performed (using abrasive-free fluid) after the perforating stage but before moving the BHA, the annulus can be closed (if circulation was occurring), and this allows using the Bernoulli Principle **(Fig. 9)** to actually increase the pressure inside the perf tunnel to a higher level than the pressure in the annulus**.**

The fluid's high-pressure energy within the tubing is transformed into kinetic energy through the jet, resulting in high-velocity streams, as demonstrated (Surjaatmadja 1998) by the following Bernoulli equation (Eq. 1):

$$V^2/2 + p/\rho + gz = C \quad (1)$$

where: V=velocity; p=pressure; ρ= fluid density; g=gravity constant; z=height; C=constant

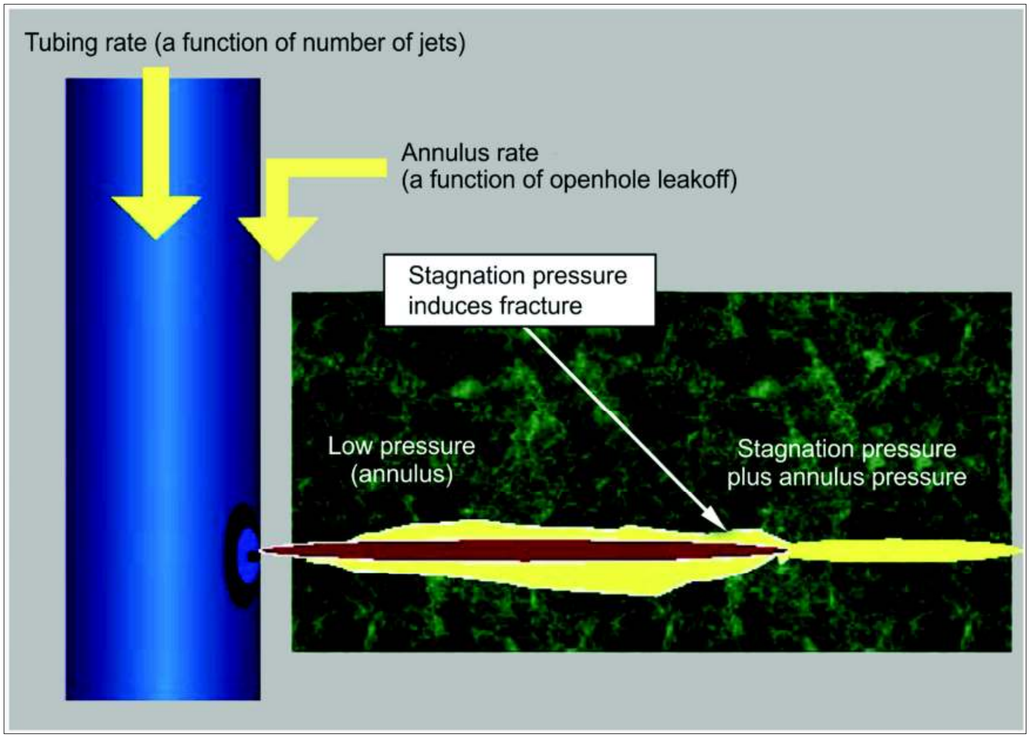

Fig. 9—Hydrajet-assisted fracturing illustrated. The jet energy is converted to pressure (Bernoulli principle) inside the eroded perforation tunnel, allowing fracturing placement with surgical precision, even in openhole completions.

For penetrating a metal liner, abrasive solids (typically quartz frac sand) are included in the jetted fluid; and, for jet nozzle delta pressures of approximately 3,000 psi or higher, it typically requires only tens of seconds to abrade a hole through a casing or a liner. Once the jet stream erodes a cavity into the rock, some of that kinetic energy is converted back to pressure, called "stagnation pressure." Stagnation pressure combined with annular pressure can result in fracture initiation from inside the jetted tunnel, while pressure inside the wellbore annulus is lower (by more than the magnitude of the stagnation pressure). The tunnel into the rock, being a much larger diameter than produced by explosive jet perforating **(Fig. 10)**, creates an extremely high NWB conductivity, especially when combined with a high proppant concentrations placed in the fracturing operations typical in PPD methods.

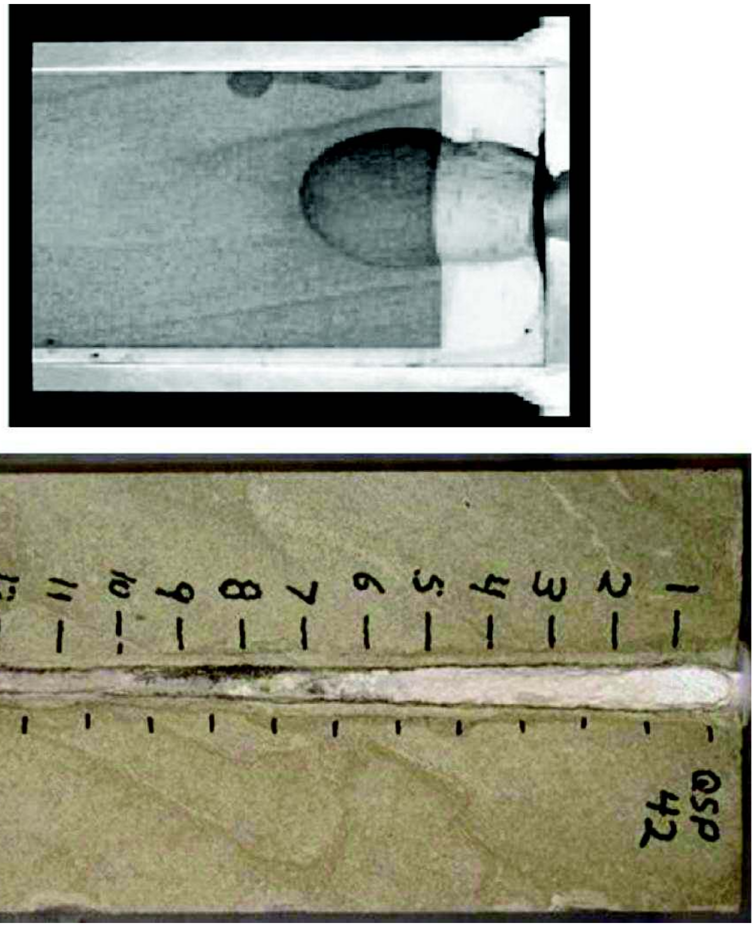

Fig. 10—Hydrajetted perforation tunnel (top) vs. explosive jet perforation (bottom). The eroded tunnel created by hydrajetting creates a large diameter lobe into the rock that provides good connectivity to fracture and high NWB conductivity. The explosive jet perforation creates a damaged region on the surface of the tunnel, caused by super-heated gases and a greater stress-compaction region around the tunnel.

The time necessary for any specific hydrajet perforating operation is not a set parameter and should be determined only after knowing the specific equipment and wellbore conditions for each application. One simple relationship to remember is that jetting time necessary and the differential pressure across the jet are inversely proportional; lower delta pressure means more time is necessary. Many variables are considered when making this determination, including jetting nozzle(s) size, jet delta pressure, jet standoff from the casing, casing thickness and hardness, and formation hardness. In some specific applications, other variables that can influence the hydrajetting process, such as multiple casing strings to penetrate, abrasive used, or possibly other factors specific to a particular case.

Hydrajet perforating will produce, in most cases, a perforation in steel (Brown et al. 1961; Pittman et al. 1961) with a diameter equal to three times the jet diameter. For instance, if a 3/16-in. jet were used to perforate through casing and cement, the resulting hole in the casing would be approximately three times 3/16 in., or a 9/16-in. diameter. In most producing wells, a limited number of 9/16-in. perforations (typically three perforations/frac interval for the HPAP with PPD method) combined with large, proppant-packed perforation tunnels is sufficient for optimum inflow performance where pumping rates for that interval are typically 3 to 6 bbl/min per perforation when they are this size.

Horizontal wells with transverse fractures can require the highest possible NWB conductivity because of potential flow convergence issues **(Fig. 11).** Not only should the perforations be sufficient to handle the flow from a fracture, but also the conductivity of the fracture surrounding the wellbore should be sufficient. The optimum design dimensionless fracture conductivity for a transverse fracture intersecting a horizontal wellbore should be maximized to overcome flow-convergence issues. This is best achieved with the HPAP with PPD method **(Fig. 12),** but a definite limitation with many of the other multiple interval fracturing methods commonly practiced today. It is this capability to create the highest NWB conductivity possible without compromising the process efficiency that distinguishes the HPAP with PPD method as an aggressive fracturing technique.

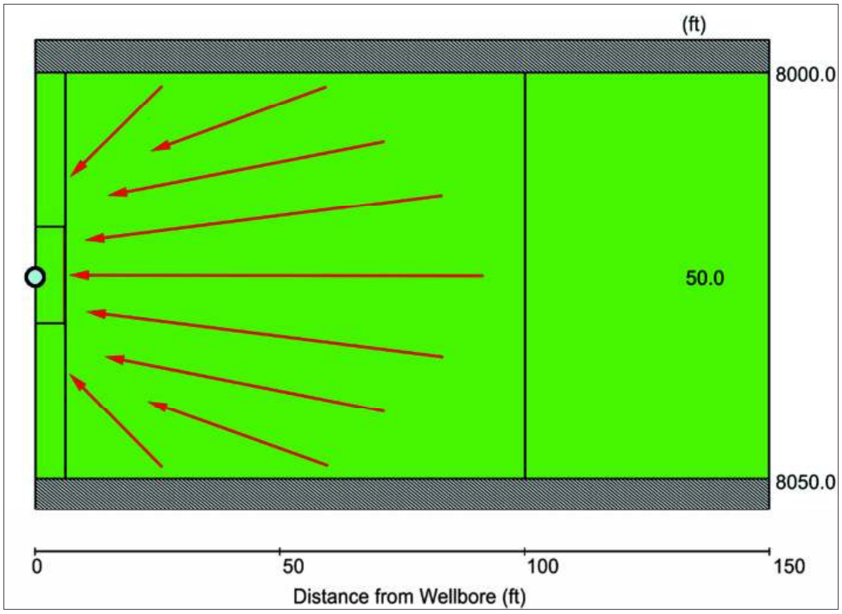

Fig. 11—Illustration of a horizontal wellbore intersecting a vertical, transverse fracture. The flow through the fracture should converge on the relatively small wellbore; therefore, for optimum stimulation design, fracture conductivity in the NWB area should be maximized.

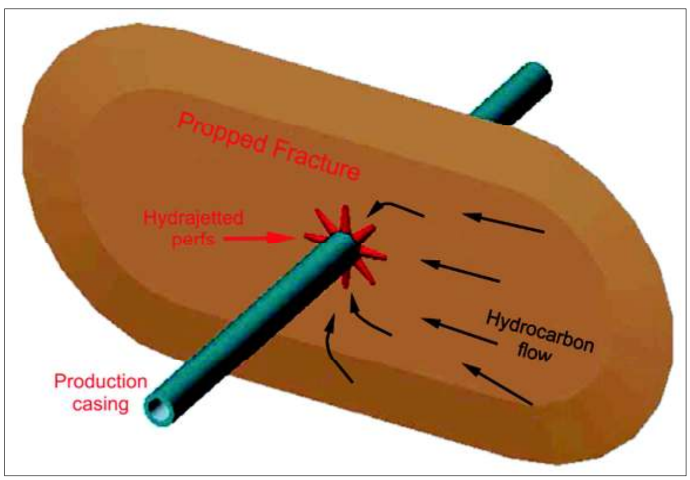

Fig. 12—Hydrajetted perforations have large inside diameters (IDs) and are undamaged, reducing restrictions to production that can occur using conventional perforating.

Proppant Plug Placement

A critical process step in the HPAP with PPD method is optimal placement of the proppant plug sufficient to act as a diversion mechanism when treating intervals further uphole and to provide the maximum conductivity possible to prevent flow convergence and perforation production restrictions. Failure to create a proppant plug that can act as a diversion mechanism for frac treatment uphole can result in long delays and completion complications (Romer et al. 2007). The NWB screenout method of placing a proppant plug after the frac treatment has been placed relies on proppant bridging in the fracture as a result of excess proppant concentration in a fracture of limited width. It is commonly recommended to pump (1) a final proppant slug concentration of 14 to 16 lbm/gal in uncrosslinked fluid and (2) a slug volume sufficient to place one-half the slug in the fracture and leave a minimum of 100 ft of slug in the casing. If the initial plug does not hold pressure on testing, usually additional wellbore sand can be washed against the plug and then achieve a pressure test. Excess proppant can be reverse-circulated out, if necessary.

Case History—Well KH-XX

Horizontal well, Well KH-1X, was geosteered in the Upper Baharyia sand/shale interbeds lying just below the Upper Baharyia 100 LST marker. The target of the well was the UB-100 Sand layer in the middle of the sand/shale thin interbeds. The well was going to be geosteered using a geological model developed based on offset wells and an expected LWD response along the proposed well trajectory. In this process, the software would be used to determine the stratigraphic location of the well path, supporting adjustments made in the well path to remain within the necessary reservoir subzone. Real-time LWD/drilling data during the actual drilling phase of the well would allow the actual log response to be compared to the expected log response and then adjust the geological model accordingly.

Originally, it was planned to drill a 12 1/4-in. build section, and complete the well as an 8 1/2-in. horizontal drainhole. Unfortunately, there were a significant number of hole problems (tight spots, packoff, stuck etc.) while drilling the 12 1/4-in. hole in an upper shale layer (Abu Roash "G" shale), and because of this, the 9 5/8-in. casing could not be set at the planned depth and a 7-in. casing was run to the top of the reservoir.

Drilling a 6-in. horizontal section was not considered during the preplanning contingency. Because of the low resistivity contrast between the different layers, the azimuthal density log was critical to placing the well within the sand, while the azimuthal resistivity log was not as effective in the nearby layers, but was good in terms of detecting the limestone marker above because of its high resistivity. The geology was not as planned because two faults were encountered during the horizontal section placement, which were not seen on the seismic log. Geosteering was crucial to putting the well back in the sand. It was planned to open the 6-in. hole to 7 in. using an under-reamer; however, because of problems with the tool, this was cancelled and a 5-in. liner was run and cemented in the hole **(Fig. 13).**

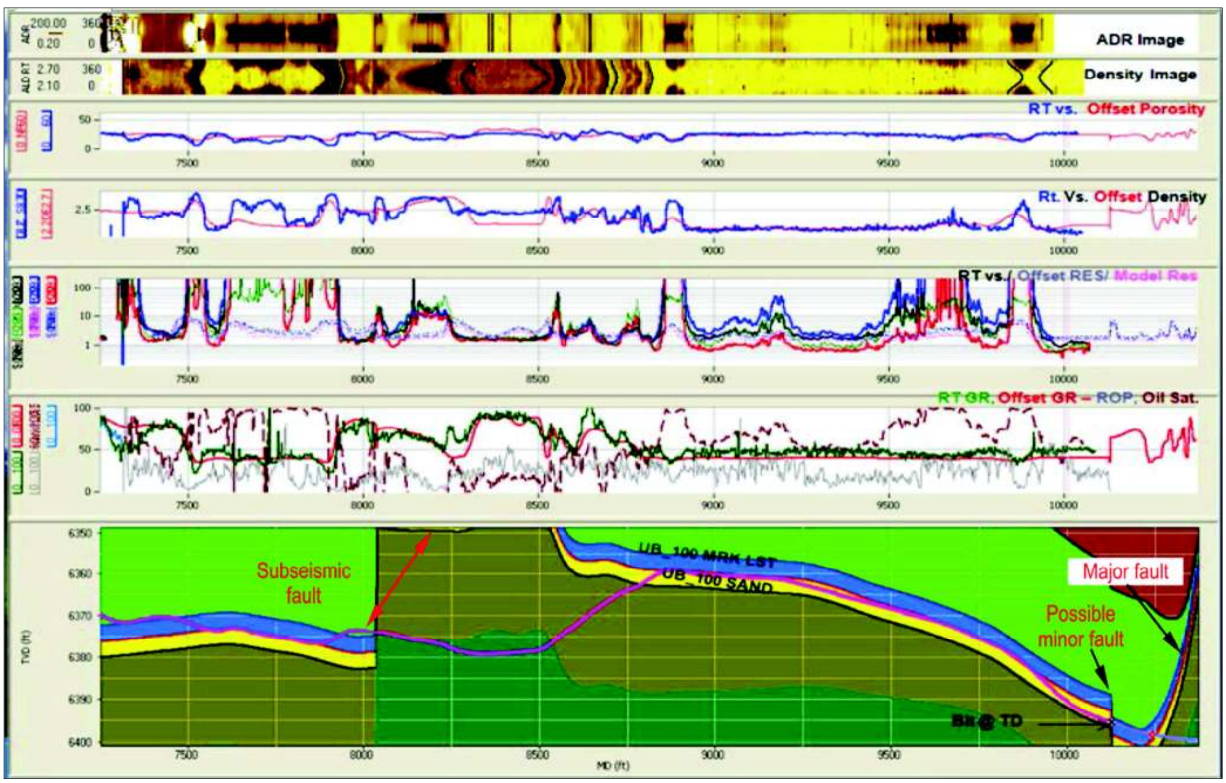

Fig. 13—Well KH-XX composite log showing well trajectory and unconformity.

Completion Features. After drilling the horizontal section of Well KH-1X, the decision was made to place six frac stages along the entire horizontal section as per the prognosis in **Fig. 14.**

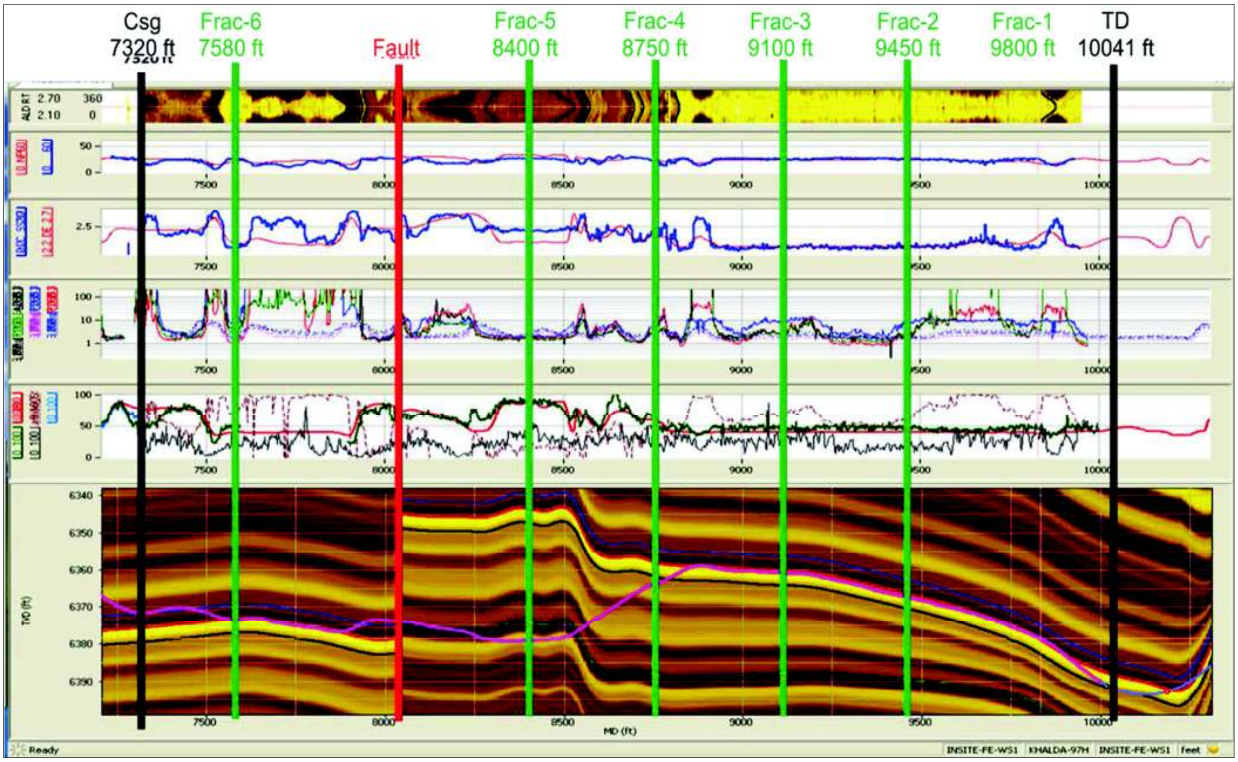

Fig. 14—Frac depths of 9,800, 9,450, 9,100, 8,750, 8,400, and 7,580 ft MD.

HPAP Fracturing Treatment. A 2.0-in. CT with a special hydrajet BHA was run in hole to the target depth in the horizontal section. The initial cut was made in the 5-in. cemented liner with proppant as the abrasive and a fracture initiated in the reservoir. The HPAP with PPD procedure is summarized as follows:

1. Hydrajet perforations and initiate fracture; pull BHA 100 to 150 ft uphole.
2. Pump frac treatment down annulus.
3. Pump frac and place proppant pack inside wellbore.
4. Move BHA above excess proppant; wash down against plug, if needed; pull BHA to above next target location.
5. Reverse up CT to wash down to next target (if needed), test plug.
6. Hydrajet perfs and initiate fracture; repeat Steps 2 through 5.
7. Repeat Steps 1 through 6 to complete six fracturing treatments (no sand plug needed after frac No. 6).

The proppant and fluid schedule that followed is presented in **Table 1** as an example.

Stage Number	Stage Description	Fluid System	Clean Volume (gal)	Slurry Rate (bbl/min)	Prop Type	Prop Conc. (lbm/gal
1	Displacement	Water Frac G 30# - SBM (15347)	8500	0.5	—	0.00
2	Shut-In		0	0.0	—	0.00
3	Circulate	Water Frac G 30# - SBM (15347)	500	3.0	—	0.00
4	Hydrajet	Water Frac G 30# - SBM (15347)	1260	3.0	Premium - 20/40,	1.00
5	Spacer	Water Frac G 30# - SBM (15347)	500	3.0	—	0.00
6	Circulate	Water Frac G 30# - SBM (15347)	6900	3.0	—	0.00
7	Breakdown	Water Frac G 30# - SBM (15347)	5000	22.0	—	0.00
8	Shut in		0	0.0	—	0.00
9	Pad	Delta Frac 200 30# 4%KCL	17000	22.0	—	
10	1 lbm/gal	Delta Frac 200 30# 4%KCL	6000	22.0	Premium Prop 20/40	1.00
11	2 lbm/gal	Delta Frac 200 30# 4%KCL	5500	22.0	Premium Prop 20/40	2.00
12	3 lbm/gal	Delta Frac 200 30# 4%KCL	5500	22.0	Premium Prop 20/40	3.00
13	4 lbm/gal	Delta Frac 200 30# 4%KCL	5500	22.0	Premium Prop 16/30	4.00
14	5 lbm/gal	Delta Frac 200 30# 4%KCL	5000	22.0	Premium Prop 16/30	5.00
15	6 lbm/gal	Delta Frac 200 30# 4%KCL	4000	22.0	Premium Prop 16/30	6.00
16	7 lbm/gal	Delta Frac 200 30# 4%KCL	3000	22.0	Premium Prop 16/30	7.00
17	Sand Plug 16 lbm/gal	Water Frac G 30# - SBM (15347)	700	22.0	Premium Prop 20/40	16.00

Table 1—Typical fluid and proppant schedule for each stage includes hydrajetting.

All of the fracturing treatments scheduled for the six intervals went as per planned, although there was much debate about the perforating depths during the treatments. In the end, it was clear that, after tagging the plugged back depth (PBTD) and marking the CT with paint, depth accuracy was within an acceptable limit. An inadvertent test of perforating depth accuracy was possible when a thin shale section, whose chances of being missed by the perforating was thought very likely. However, when hydraulically fractured, the pressure response was markedly different from the sandstone fractures, clearly indicative that the perforations were indeed cut in the shale zone.

The hydrajet abrasive perforating was fast and trouble free. The proppant diversion slugs placed after each treatment to isolate the zones were easily placed and proved to be good, competent barriers. Each fracturing treatment had its own fracturing signature indicating it was not communicating with the previous zones.

It is noteworthy to comment that while the maximum proppant concentration placed in the Upper Bahariya formation in conventional fracs has been 6 to 7 lbm/gal, during these treatments, up to 16 lbm/gal was placed successfully. Higher proppant concentrations at the tail end of the fracturing treatment increases the NWB area conductivity and provides better communication with the reservoir. Although such high proppant concentrations were placed primarily for isolation purposes, this insight provided an opportunity to increase the productivity of other laminated layered formations where aggressive treatments can be placed using the HPAP with PPD process.

Post-job cleanups were excellent considering proppant settling can be an issue in horizontal wells. The smaller than planned 5-in. liner improved the ability to clean sand from the wellbore after the job.

There were, however, operational challenges during the process of treating the well. On one occasion, the BHA was lost in hole because of improper pinning of the shear disconnect tool. The tool was fished out successfully. An evaluation was made regarding its utility and whether the shear disconnect needed to be included in the future.

The flowback choke manifold used on surface to capture the return fluids had the standard stem and seat type chokes. These chokes showed noticeable erosion when the abrasive fluids used for perforating were circulated out. Hydraulic adjustable chokes that do not use a stem and seat would be preferable; these types of chokes are more durable and can be operated remotely. Hydraulic chokes would be a better choice going forward.

Approximately 0.9 million pounds were pumped with 150 thousand pounds per each zone, in addition to the sand used during hydrajet perforating.

Case History- Well UMB-2XX

Following the successful production results from the first well in the Khalda field, the second UBAH formation well was targeted in the Umbaraka field, Block 3.

Drilling Features. Horizontal Well UMB-2XX was drilled to total MD of 9,808 ft, rig Kelly bushing (RKB). The well was drilled vertically to a depth of 5,700 ft kickoff point (KOP) and then began building angle until 7,200 ft, RKB (landing point) and was covered with 7-in. casing. The horizontal section was drilled from 7,200 until 9,808 ft, RKB (TD) and was covered with 5-in. cemented casing (2,608-ft interval). The petrophysical analysis of the well showed 1,668 ft pay length with 24.8% average porosity.

HPAP Multistage Fracturing. This was the second well using the HPAP with PPD method for the multistage fracturing job. The final completion diagram is shown in **Fig. 15,** (similar to that of the earlier well KH-1X). There were seven frac stages planned on this well from depths of 9,700, 9,305, 8,945, 8,550, 8,150, 7,800, and 7,450 ft, choosing from the best intervals in the horizontal pay (Fig. 15). After gaining the experience and the lessons learned from the first well, the entire process was tremendously streamlined and the seven hydraulic fracturing treatments were performed in approximately 76 hours. The treatments were performed with zero issues on location in terms of health, safety, and environmental aspects. This was quite an achievement when performing multiple stage treatments.

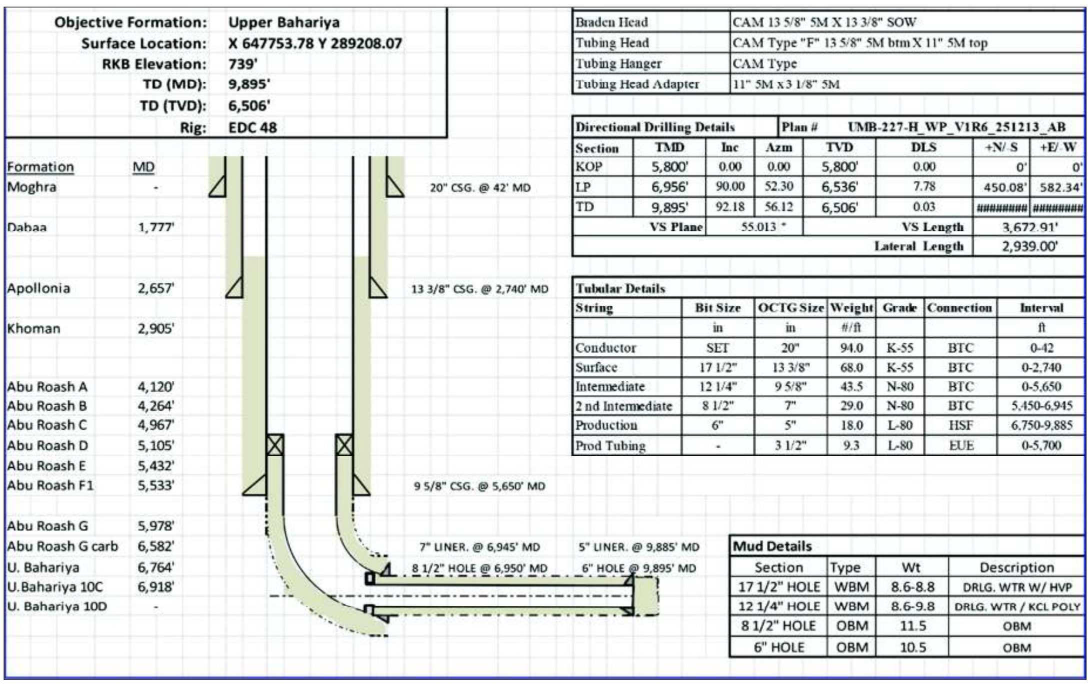

Fig. 15—UMB-2XX horizontal well completions design.

Almost 1,200,000 lbm of proppant was pumped with 165,000 lbm per each zone in addition to the sand used during hydrajet perforating. A smooth well cleanout and lifting operation was performed after the fracturing treatments. Examples of the fracturing treatment charts are shown in **Figs. 17 through 19.**

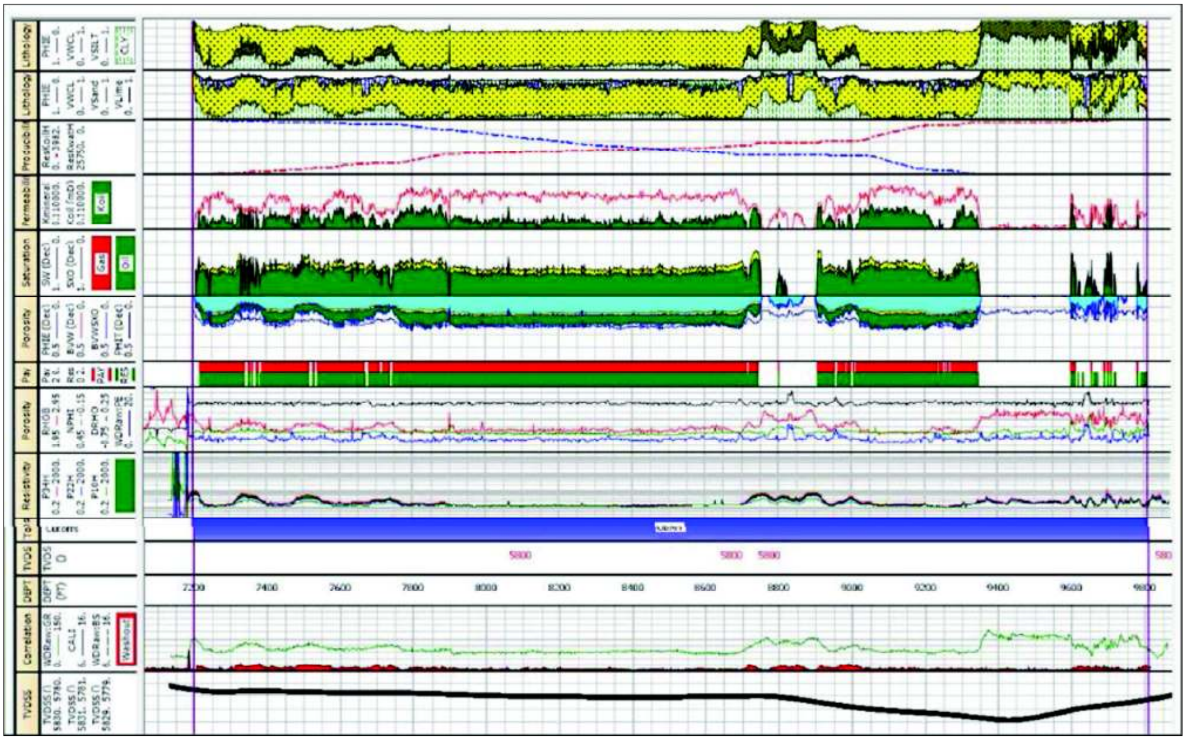

Fig. 16—Well UMB-2XX; frac depths of 9,700, 9,305, 8945, 8,550, 8,150, 7,800, and 7,450 ft MD.

Fig. 17—First stage hydrajetting perforations.

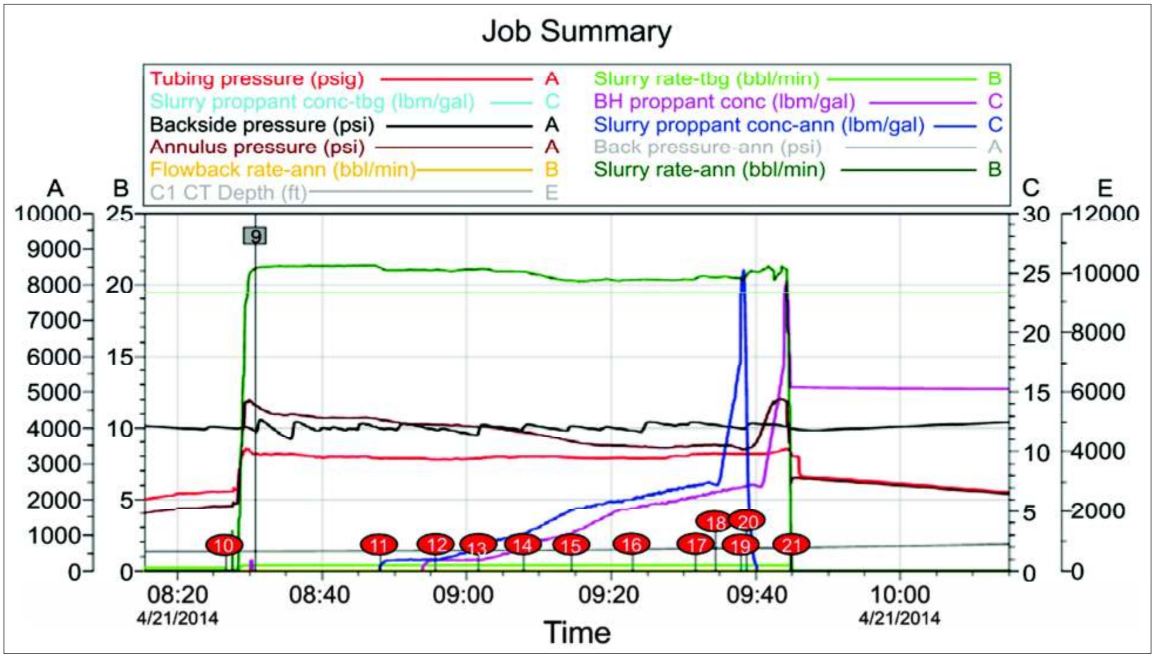

Fig. 18—First stage treatment.

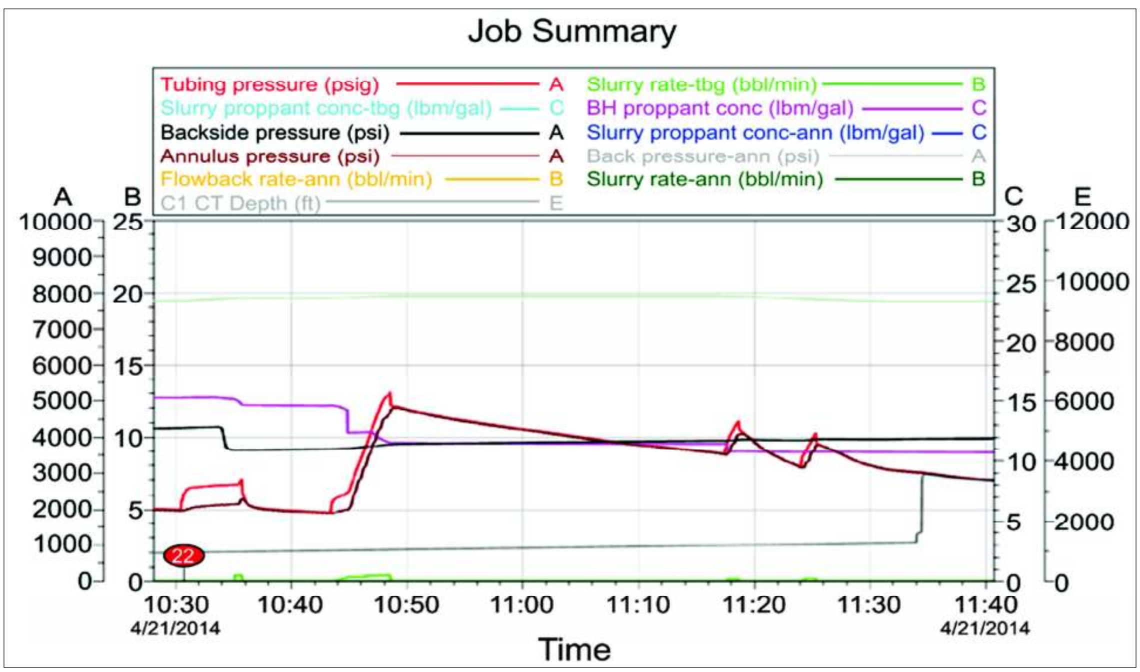

Fig. 19—First stage sand plug.

Well Performance

The first well (KH-1X) was put on production with an electric submersible pump (ESP) and produced more than 1,200 B/D with 42% water cut. There was a rapid decline in fluid rate and bottomhole flowing pressure, measured using a bottomhole sensor. Two months later, the well was shut in because of a drop in reservoir pressure from 2,200 psi initial pressure to 900 psi. The ESP was replaced by a sucker rod pump (SRP) to produce 216 BOPD and 4% water cut and the well accumulated oil of 91 MSTB within one year of production. This production data is an enhancement from 37 to 70% of recoverable reserve with the recovery factor being doubled. Additionally, from an expenditure perspective, this means a reduction from the drilling of three vertical wells and has direct economic benefits through reducing the installed artificial lift strings, related expensive artificial lift equipment repairs, and the future number of workovers required.

Conclusions

- Well Khalda-1X represented the first success in which the operator applied an unconventional development strategy for a marginal reservoir. The second well was an endorsement of the successful use of this multistage fracturing technology.
- A method of hydraulic fracturing treating multiple interval completions using CT and PPD was applied.
- The method presented improved process efficiency by eliminating the need for special trips in and out of the wellbore to perforate. This was done using hydrajet perforating and placing the fracture treatment without pulling CT out of the hole between treatments.
- The HPAP with PPD method has been shown to help reduce risk in horizontal well completions that require fracture stimulation compared to other conventional methods while allowing for aggressive frac designs.
- The HPAP with PPD method was proven to be a flexible process for many types of completions.
- The collaborative work environment between the operating company's technical teams and the service provider's multiple product line technical teams was crucial to achieving success in these wells. The well plans were achieved with multiple challenges faced during the operation. Additionally, the wells delivered the expected production and proved the applicability of the development strategy.

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