SPE 39941

A Case History: Completion and Stimulation of Horizontal Wells with Multiple Transverse Hydraulic Fractures in the Lost Hills Diatomite

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This paper was prepared for presentation at the 1998 SPE Rocky Mountain Regional Conference, Denver, U.S.A., 1998.

Abstract

The Lost Hills Field Diatomite has traditionally been developed using vertical wells completed with multiple propped hydraulic fracture treatment stages. As the main portion of the field is nearing full development at 2½-acres per producer, the search for additional reserves has moved out to the flanks of the field's anticlinal structure. Due to limited pay thickness, these flank portions of the field will not support economic vertical well development. The use of horizontal wells was determined to have the best chance to economically develop these areas of the field. To evaluate this development concept, three horizontal wells were drilled and completed over the time period from November 1996 to December 1997.

To assist with the horizontal well design and evaluation, several vertical data wells were drilled offset and parallel to the intended well path of each horizontal well. Additionally, two vertical core wells were drilled in line with the toe and heel of the horizontal well paths. These data wells were utilized to estimate properties such as in-situ stress profiles, pore pressure gradients, rock properties and fluid saturations, and to determine horizontal well vertical depth placement. The horizontal wells were then drilled in the direction of minimum horizontal stress (transverse to the preferred hydraulic fracture orientation) and completed with multiple-staged propped hydraulic fracture treatments.

During the completion of the three horizontal wells, hydraulic fracture growth behavior was characterized using surface tiltmeter fracture mapping and real-time fracture pressure analysis. In the third horizontal well, downhole tiltmeter fracture mapping was also used. This combination of fracture diagnostics provided significant insights into hydraulic fracture behavior, allowing diagnosis of anomalous fracture growth behavior and evaluation of remediation measures. Fracture diagnostics during the first horizontal well revealed an unexpectedly complex near-wellbore fracture geometry, a result of fracture initiation problems. These problems slowed the completion process and severely harmed the effectiveness of the fracture-to-wellbore connection. In the subsequent horizontal wells, a number of design and execution changes were made which resulted in simpler near-wellbore fracture geometry and a greatly improved production response.

The paper provides an overview of the completion and stimulation of all three horizontal wells, describes the lessons learned along the way, and discusses the implications for future Lost Hills horizontal well development.

Lost Hills Field Setting and Horizontal Well Rationale

Field Description. The Lost Hills Field is an asymmetric anticline, approximately one mile wide and twelve miles long, located in Kern County, California, approximately 45 miles northwest of Bakersfield (see **Figure 1**). The anticline trends NW-SE, nearly parallel to the San Andreas Fault. The main reservoir is approximately 1000 ft thick, occurring at depths ranging from 1000 to 3000 ft.

The main reservoir rock is the Belridge diatomite, which has a primary constituent of siliceous shells that are the remains of single-celled, algae-like plants called diatoms. These diatoms were plentiful in the shallow marine environment during the late Miocene (5-10 million years ago), in what is now California's San Joaquin Valley. Due to the open structure and round shape of the small (50 μm-diameter) diatoms, porosity can be as high as 65%, while permeability is typically much less than 1 mD (see **Table 1**). With such high porosity, lithostatic (overburden) gradients are relatively low at 0.79 - 0.82 psi/ft.

The thickness of the reservoir ranges between 600 and 1200 ft. Throughout the field, key reservoir properties change at a depth varying between 1900 and 2700 ft, where the

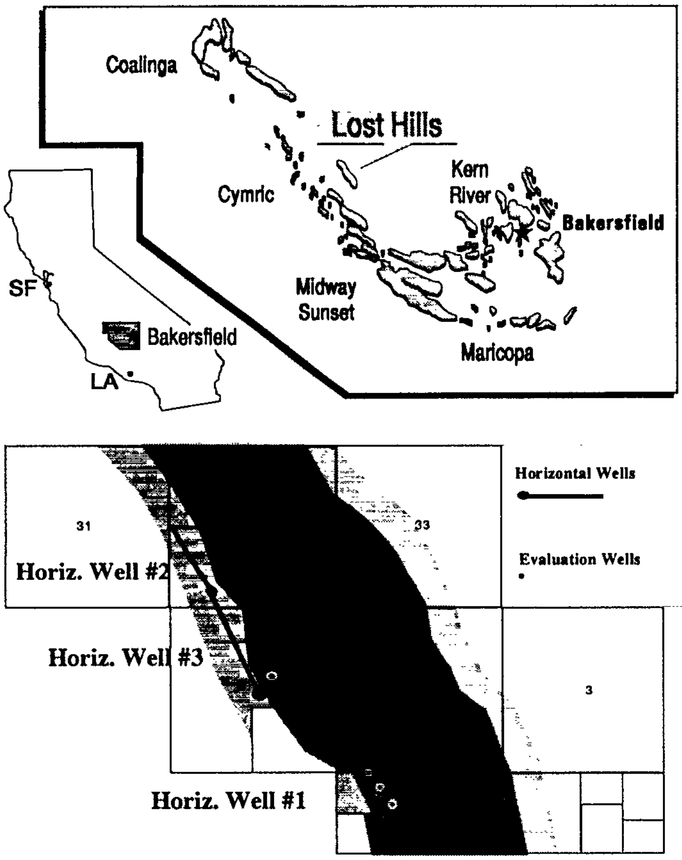

Figure 1: Location of the three horizontal wells and the "horizontal analog" vertical wells in the Lost Hills Field in the San Joaquin Valley in California.

originally deposited amorphous silica (Opal A) changes gradually into a tetragonal or hexagonal crystalline structure (Opal CT). With the biogenic silica phase change, porosity and permeability decrease variably, depending on the total rock constituents. Young's modulus also varies with these changes. The Young's modulus of Lost Hills Opal A diatomite averages approximately 100,000 psi whereas the Opal CT modulus is about 500,000 psi.

Table 1: Rock mechanical properties of Lost Hills Diatomite

Property	Unit	Value
Depth	ft	1000 - 3000
Thickness	ft	600 - 1200
Young's modulus	psi	50,000 – 1,000,000
Poisson's ratio	-	0.25 – 0.35
Permeability	mD	0.01 – 100 (avg. 0.1)
Porosity	%	35 – 65
Oil Saturation	%	25 – 50
Frac closure gradient	psi/ft	0.55 – 0.65

Development History. Reservoir characteristics at Lost Hills result in generally decreasing reservoir quality with depth, which is reflected in the development history. In the early part of this century, wells were drilled only to the upper parts of the reservoir, and the flowing wells were completed with slotted liners. By mid-century, wells were generally limited to the upper half of the reservoir and slotted liners were the norm. Production rates in these wells were greatly diminished from earlier wells due to partial reservoir depletion and the general decrease in reservoir quality with depth. Since the mid-1970's, wells have commonly targeted the entire Belridge and deeper intervals with the development of hydraulic fracture stimulation technology.

Today, hydraulic fracture stimulation is routinely performed on a large scale to enable production from the diatomite formations. However, the low permeability and low Young's modulus of the rock make achievable fracture lengths quite short. Thus, well drainage radius is small, leading to the current primary development at 2½ acre well spacing while areas under waterflood are at 1-1/4 acre spacing (one injector per 2½ acre pattern). Further infill drilling to spacing as small as 5/16 acre is under evaluation and testing. Such tight spacing may be necessary to effectively produce the mobile fraction of the estimated 2 billion barrels of oil-in-place in the Lost Hills Field.

Horizontal Well Justification. Multi-stage fractured horizontal wells are being tested as a way to develop reserves in the relatively thin pay interval along the flanks of the Lost Hills Field. As shown in **Figure 2**, vertical wells with multiple stacked fracture stages are advantageous where the gross pay is thick and multiple reservoirs are targeted. However, as the diatomite pay thins toward the flanks of the anticline, the number of stages becomes very limited and vertical wells become less economic. In these areas, horizontal wells with multi-stage, transverse, propped fractures targeting a selected

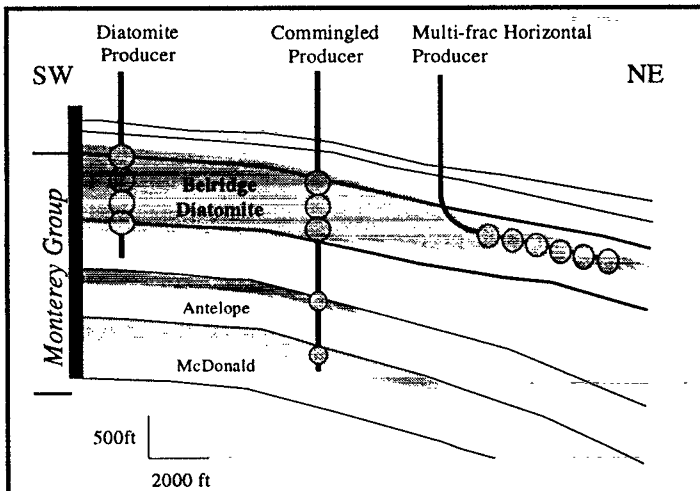

Figure 2: Motivation for horizontal drilling and multi-zone completions at the flanks of the Lost Hills Field.

diatomite interval can provide economic development and thus, provide additional reserves. Horizontal wells have been beneficial in numerous areas[1-3], but wellbore-to-fracture communication problems in other diatomite reservoirs have shown that successful completion of horizontal wells may be challenging[4].

Due to the very low permeability (0.1 mD average), both vertical wells and horizontal wells in the Lost Hills Field require hydraulic fracturing. Therefore, the number of hydraulic fractures required for a given reservoir volume is the same regardless of how they are connected to the wellbore. The actual costs for drilling and completing the horizontal wells is about 450% that of a conventional vertical multi-stage completion in the heart of Lost Hills. However, in the flank areas, the horizontal wells to date are only 75% of the cost to develop the same reservoir volume using vertical wells. Assuming future optimization, horizontal well costs are expected to reduce to only 50% of that which would be required by vertical wells. It is the ability to include numerous fracture stages in a single horizontal wellbore, that provides the cost advantage over vertical wells and the opportunity for reserve additions along the flanks of the field.

The technical objective during this initial phase of the project has been to develop an understanding of the completion and production behavior of horizontal wells, using a combination of comprehensive field measurements and diagnostic procedures. Measurements and diagnostic techniques included special borehole imaging logs, special coring and core analysis, diagnostic fracture injections, fracture net pressure analysis[5-9], surface and downhole tiltmeter fracture mapping[10-15], and post-fracture production analysis.

Figure 1 shows the location of the wells that were involved in this pilot study.

Horizontal Well Design

Placement of the Horizontal Section. With the goal of creating transverse hydraulic fractures (fractures that are oriented roughly perpendicular to the wellbore), the horizontal wells were drilled in a direction of about N 25 - 40° W, which is approximately orthogonal to the Lost Hills Field average fracture azimuth as determined by surface tiltmeter fracture mapping[10,11]. The stratigraphic placement of the horizontal sections were determined using stress profiles (micro-frac data, dipole sonic logs and reservoir pressure tests[7,16]) and reservoir quality (core and log data) from offset vertical wells. In addition, several evaluation wells were drilled near the proposed horizontal well paths for data collection. These evaluation wells were also completed to obtain production data prior to drilling each horizontal well.

The vertical well data improved fracture modeling, geostatistical simulation and 3D visualization for final target interval selection and horizontal wellpath definition. All of the wellpaths to date have medium radius build rates and near-horizontal lateral sections to stay within a specific geologic interval. The final inclination of a wellbore is dependent upon the desire to maintain a wellpath that is roughly orthogonal to anticipated fracture azimuths, constraints of existing wellbores, reasonable alignment with the vertical well development and of course, the structural attitude of the target zone.

To date, the target zone for the horizontal wells is within the transition zone from Opal A to Opal CT diatomite. Reservoir characterization consistently indicates that this interval offers the best combination of oil saturation, porosity and permeability. Shallower, Opal A zones, which have somewhat higher permeability (1 mD), exhibit reduced oil saturation and reservoir pressure. This likely reflects the influences of the long history of up-dip, vertical well development. Below the transition zone in the Opal CT, matrix permeability is extremely low (< 0.1 mD) and natural fractures are more prevalent. These fractures may allow the secondary hydrocarbon migration vertically into the transition zone where natural fracture counts are reduced and effective porosity and permeability has not been reduced by the silica phase transition.

By targeting the transition interval, the horizontal well fractures effectively extend the wellbore into zones with relatively high oil saturation and porosity while their lower extremes intersect the natural fractures that are prevalent in the Opal CT.

Casing Design. The mechanical detail of the first two horizontal wells consisted of an intermediate string of 9-5/8" casing cemented at the end of the build section (see **Figure 3**). At inclinations of no more than 95°, the lateral sections of 1350' and 2000' were drilled for wells #1 and #2 respectively. The horizontal sections received 5½" casing from TD to approximately 80° inclination, where it was then crossed over to a 7" casing string to surface. The 5½" casing was then

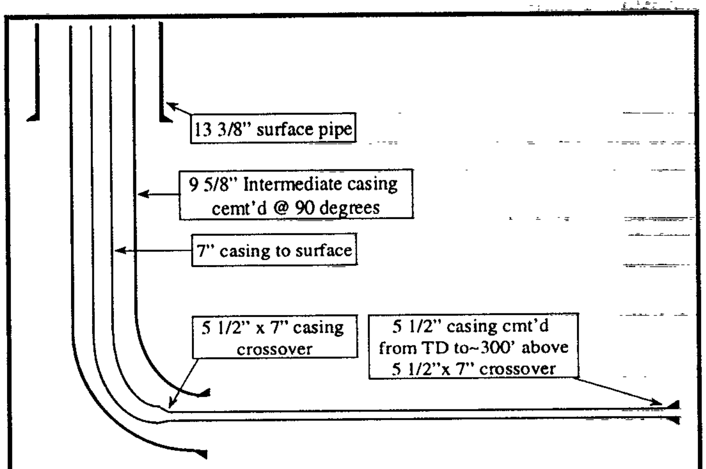

Figure 3: Horizontal wellbore mechanical diagram for well #1 and #2.

cemented in place, with a programmed cement top several hundred feet above the 5½"x 7" crossover.

The partial string of 7" casing was installed in the first two horizontal wells to accommodate larger artificial lift equipment. Soon after the initial production of wells 1 and 2, it became apparent that the wells did not require larger artificial lift equipment, thus the change to 5½" casing from TD to surface in well #3. Additionally, the 5½" x 7" casing crossover acted as a receptacle for wellbore debris (proppant). The debris caught in the crossover caused severe plugging problems during fracture initiation on well #1 (the problems associated with this plugging on fracture geometry and net pressure response will be addressed later in the paper). At the outset however, it was unknown what was causing these initiation plugging problems. After encountering several frac stages with little to no fluid injectivity, the source of the plugging problem was finally identified as debris left in the crossover. Insufficient circulating velocities (<300 ft/min) during wellbore cleanouts between frac stages in well #1 was determined to be the primary cause for debris collection. Modifications to the circulating rates and procedures were implemented in an attempt to achieve satisfactory cleaning of both the horizontal section and crossover.

The changes in cleanout procedures were adequate to continue, but still did not entirely solve the plugging problems during fracture initiation on well #1. By the time the 5½" x 7" casing crossover problem was identified, horizontal well #2 had already been completed with an identical casing string design.

As stated previously, well #3 received 5½" casing from TD to surface, and was drilled at a maximum inclination of 88°. Fracture plugging problems associated with wells #1 were never seen on wells #2 and #3, as adequate circulating and reverse circulating procedures had been implemented to clean out sand from the fracture treatment.

Cementing Program. Similar cement programs were utilized on all three well. The intermediate casing was cemented with a foamed lead slurry followed by a Class C tail slurry. The tail slurry was targeted to cover the build section, up to the initial kick off point. The foamed lead slurry was required to keep from exceeding the formation fracture gradient. The horizontal section was also cemented with a Class C base slurry with several additives. The main requirements for this slurry were 1) light weight, 2) excellent rheologic properties, 3) no free water, and 4) low fluid loss.

Cement bond evaluation was attempted on the horizontal section of well #1. The results were inconclusive. Therefore, attempts to evaluate the cement bond on the remaining wells was not implemented. It is possible that inadequate cement bond may have played a role in the abnormal initiation, and growth of fractures seen in both wells #1 and #3.

Perforating, Stage Spacing and Isolation. To minimize the creation of multiple fractures upon initiation, point source perforating was utilized. Each stage was perforated with 12 (½") jet holes over one foot. The perforating charges were phased at 30°. Perforating guns were conveyed via coiled tubing and fired utilizing a pressure actuated firing head.

Stage spacing was determined from a number of factors. In well #1, frac stages were spaced approximately 130 ft apart, due to the lower average permeability in this part of the field and due to limitations imposed by offset vertical wells. In wells #2 and #3, the frac spacing was increased to approximately 170 ft as a result of existing wells and budgetary constraints.

Isolation between stages was achieved with the use of drillable composite bridge plugs. Other methods of stage isolation were considered (i.e. a multi-set retrievable bridge plug, stacking several retrievable bridge plugs, etc.) but all were deemed to have greater risk than the operating company was willing to accept.

Completion Operations. All operations were planned to be rigless, performed only with the use of a 2" coil tubing unit. Operations such as perforating, and setting bridge plugs, were performed routinely and without incident. As previously mentioned, debris collection in the casing crossover could not be removed by the maximum circulating rates achieved with the coil tubing. Modifications to the cleanout procedures were made which included reverse circulations via coil tubing between stages, conventional circulations during drill-out of composite bridge plugs, along with occasional viscous pill sweeps during both operations.

Drilling of the composite bridge plugs with a progressive cavity motor proved to be the most difficult portion of completion. Initial attempts to drill the composite bridge plugs met with limited success as insufficient circulating rates in combination with fluid loss to the hydraulic fractures severely limited cuttings transport to surface. A rig had to be utilized for this portion of the completion for the first two wells. However in well #3, the installation of 5 ½" casing to surface allowed the coil tubing unit to successfully drill out all 11 composite bridge plugs.

Hydraulic Fracture Design and Evaluation

Real-Data Approach. Over the course of the three horizontal wells, *real-data feedback* was utilized to the maximum extent possible for completion and fracture design, evaluation, and refinement[5,9]. Implicit in this approach is the recognition that hydraulic fracture behavior is complex and variable, severely limiting the usefulness of traditional predictive mode or "one size fits all" approaches.

Key issues for successful hydraulic fracture stimulation of a horizontal well are: (1) to assure that fractures effectively cover the intended pay interval height; and, (2) to assure that the connection between the wellbore and the far-field fracture is adequate[4], considering both proppant placement during treatment execution and post-frac production response.

Based on information obtained from vertical "data wells" located along the horizontal wellpaths, and conventional vertical well fracturing experience, initial fracture designs were developed for each of the horizontal wells. A fracture closure stress profile was developed using micro-frac and pore pressure measurements, combined with sonic log results. Using this closure stress profile and an estimate of net pressure, a 3-D fracture growth simulator was used to determine the horizontal well vertical depth location, and to decide initial fracture treatment size.

During the course of fracture stages in each horizontal well, a combination of direct and indirect fracture diagnostic techniques were utilized to provide feedback for fracture and completion design refinement. Surface tiltmeter fracture mapping[10-13] and real-time fracture pressure analysis[5,9] were performed to: (a) estimate fracture dimensions; (b) determine approximate fracture location with respect to the perforations; and, (c) evaluate the effectiveness of the wellbore-to-fracture connection. In addition, fracture height was directly measured during four stages in well #3 using a wireline-deployed downhole tiltmeter array located in a nearby vertical well[14,15].

Three diagnostic fracture injections were generally performed prior to each propped fracture stage, including two water (KCl substitute) injections and a crosslinked gel injection. The purpose of these injections was to: (a) provide analysis "anchor points" such as fracture closure pressure, leakoff behavior, and net pressure trends for net pressure history matching[9]; and, (b) characterize the wellbore-to-fracture connection, using a combination of rate stepdown tests[6] and proppant slugs[17,18].

Net pressure history matching involves determining the actual or "observed" net pressure within the fracture, and then adjusting simulator input parameters to match theoretical "model" net pressure with the observed net pressure response. While net pressure history matching does not assure that the correct fracture geometry is modeled, it at least provides a consistent framework for analysis and stage-by-stage comparison, and the solutions are firmly linked to actual treatment behavior.

Fracture Design. The basic frac design consisted of the following (Note: all fluid injections were ended with a rate stepdown test[6] to assist with evaluating the near-wellbore wellbore-to-fracture connection):

1) Perform diagnostic water injection(s) using KCl substitute;
2) Conduct a crosslinked minifrac containing (a) proppant slug(s), overflushed past the perforations using linear gel;
3) Tailor the pad volume with respect to the observed leakoff rate, to shorten closure time and thus lessen proppant redistribution during fracture closure;
4) Adjust fracture treatment size (within practical limits) to achieve desired geometry);
5) Pump propped fracture treatment using a 25-35 PPT (higher gel loading when tortuosity level is higher) Borate crosslinked gel fluid system, at rates of 45-50 BPM, with 20/40 Ottawa sand proppant. Proppant concentration was ramped quickly to a maximum of 12 PPG. The last 25% of the sand contained a fibrous proppant flowback control additive;
6) Set a composite bridge plug via coiled tubing half the distance between last perfs and next stage perfs;
7) Clean the remaining proppant from wellbore using coiled tubing;
8) Perforate next point source (1 ft @ 12 SPF) interval via coiled tubing; and,
9) Repeat for subsequent stages.

Overview of Hydraulic Fracture Completion Observations and Conclusions

In this section, the general observations and conclusions for each horizontal well completion are summarized. The following section will then address selected issues and results in a more detailed manner.

In general, highly variable hydraulic fracture behavior was encountered, but there were consistent behavior trends in each well. The transition from the routine, manufacturing-mode completion of conventional vertical Lost Hills wells to the horizontal well completions involved a steeper learning curve than originally anticipated, especially in terms of wellbore cleanout and fracture initiation. Thus, there were significant changes in procedures from well to well.

Table 2 summarizes the differences in completion procedure, fracture treatment behavior and results for all three horizontal wells. **Figure 4** summarizes the estimated propped frac vertical height coverage for all fracture stages.

Well #1. The hydraulic fracture behavior of Chevron's first horizontal well in the Lost Hills Field was dominated by problems resulting from insufficient wellbore cleanout between stages.

Starting with stage 3, proppant left in the crossover from 5-1/2" to 7" production casing (located at the beginning of the horizontal section) caused problems with fracture initiation and breakdown. The initial breakdown injection tended to mobilize and transport the leftover proppant to the perfs. Before any significant fracture width was created, resulting in partial or total plugging of the near-wellbore fracture region. The problem worsened with succeeding stages, as the volume (casing length) between the crossover and the perforated interval decreased.

The plugging and packing of the perforation region with proppant during breakdown resulted in highly abnormal fracture behavior, as the preferred fracture initiation plane(s) were screened out and formation stress in the perforation region was increased. Breakdown injection ISIP's climbed to well above overburden stress, and net pressures were

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