Up, Up and Away! Fracture Growth from Horizontal Wells in the Lost Hills Field

THE SETTING

- **Lost Hills Field**
- **Kern County, CA**
- **2000' Depth**
- **Low-permeability Diatomite**
- **Multi-Stage Horizontal Well Stimulation**

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Figure 1. Horizontal drilling and multi-zone completions at the flanks of the Lost Hills Field.

THE BACKGROUND

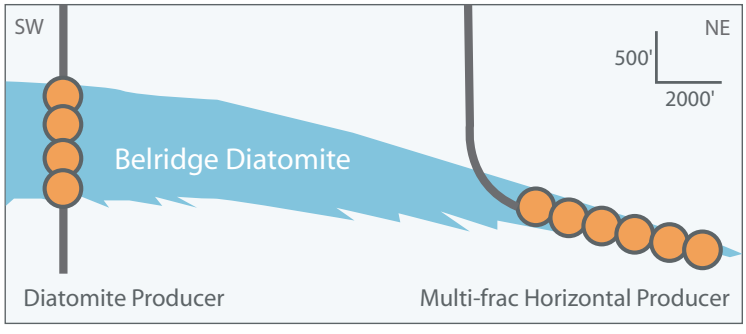
The main reservoir in the Lost Hills field is the oil-bearing diatomite, which ranges from about 600 to 1200' in thickness and is found at depths of 1000 to 3000'. The permeability of this diatomite reservoir ranges from 0.01 to 1 mD. Due to the low permeability, well spacing is small and hydraulic fracture stimulation is required to achieve economic production rates. With such tight well spacing, knowing fracture orientation is critical to optimize well placement and waterflood efficiency. Also, multi-staged hydraulic fracture treatments are required to effectively drain this thick pay interval, and optimization of fracture treatment size and number of stages is critical for economic field development. Chevron's search for new reserves in Lost Hills has moved to the flanks of the field's anticline structure. As the pay thickness is much less on the flanks (see Figure 1), vertical well development is not economic. Horizontal wells are thought to have the greatest chance of economic flank development. To date, three horizontal wells have been drilled and completed by Chevron with multiple (7 to 12) propped fracture stages. All three of these wells are described in detail in SPE paper #39941.

PINNACLE PERFORMS

Pinnacle's surface tiltmeter fracture mapping results from nearby vertical wells were used to determine the azimuth of the horizontal well to obtain multi-stage transverse fractures (see Figure 2). As the average fracture azimuth in this part of the Lost Hills field is about N 47° E, the horizontal wells were drilled along a NW-SE orientation. Pinnacle Technologies also assisted Chevron with fracture engineering on all three wells. Proppant placement problems on the first well were overcome by utilizing an aggressive fracture initiation strategy, using small perforated intervals, extreme overbalance perforating, high rate initiation with viscous pills, and an aggressive proppant slug strategy. These procedures were critical for the proppant placement success in all these wells, and key to the favorable production response in well 2. Surface tilt fracture mapping on these wells indicated that hydraulic fractures grew predominantly upward in well 1 and 3, with no significant downward fracture height growth. To measure fracture height growth more accurately, downhole tiltmeter mapping was employed on well 3 to map the fracture growth on four treatment stages. A downhole tiltmeter array was installed in an offset producing well and four fracture stages were monitored.

THE RESULTS

Figure 3 shows fracture height growth for wells 2 and 3, showing an alarming lack of payzone coverage in well 3. Downhole tiltmeter fracture mapping on the four stages mapped with a downhole tiltmeter array indicated an average downward fracture growth of only 15' below the wellbore and an average upward fracture height growth of 320'. Clearly growth asymmetry this severe must be accounted for when choosing a well path within the target pay interval. As illustrated in Figure 3, about 40% of the pay below the wellbore was not



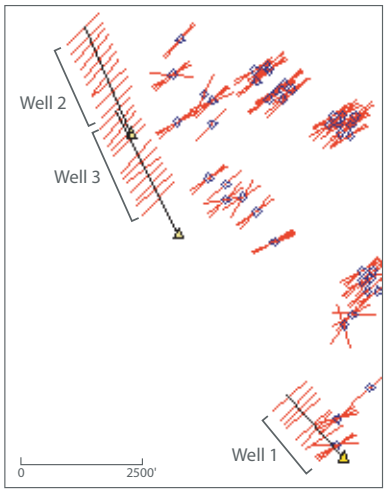


Figure 2. Plan view of fracture azimuths determined from surface tiltmeter fracture mapping in Chevron's lease of the Lost Hills Field.

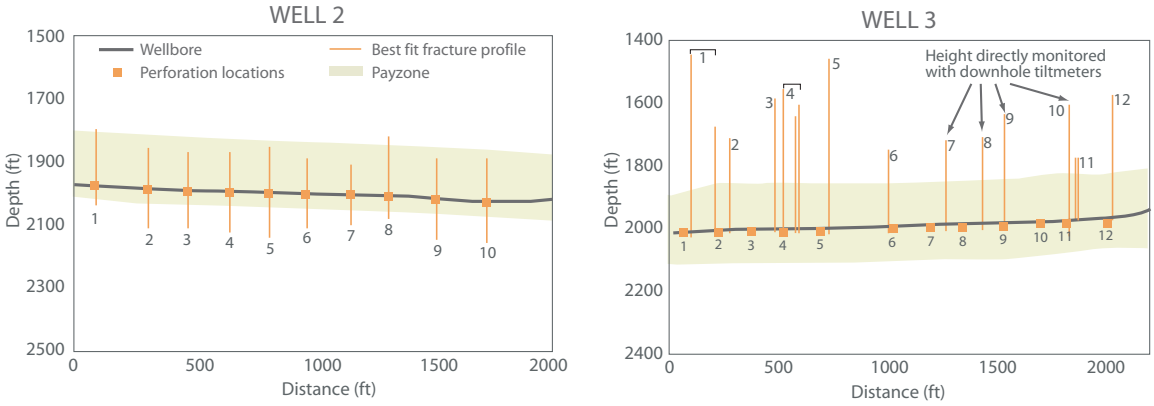


Figure 3. Estimated fracture height coverage for multi-stage horizontal well 2 and 3, with fracture height directly measured using downhole tiltmeter fracture mapping in stages 7 through 10 in well 3.

stimulated and a great deal of proppant was placed above the top of the target pay. As shown in Figure 4, the lack of payzone coverage is also reflected in the IP's of the two wells: the 12 stages in well 3 IP'd at 320 bopd, while the 10 stages in well 2 IP'd at 440 bopd.

Why did the fractures grow so dominantly upward? Stress testing in vertical offset wells indicated moderately lower stress (depleted) intervals located above the target diatomite interval. Fracture modeling with these measured stress profiles indicated more upward than downward height growth, hence the selection of a wellpath with 60% of the pay above the wellbore. Direct diagnostic measurements revealed that the growth asymmetry was far more severe than originally expected, most likely due to more depletion than expected in the layers above the pay. The extremely low closure stress in the layers immediately above the pay was confirmed by the observation of near zero or "negative" net pressures at shut-in.

The sub-par production response of well 3, as compared to the production from the previous horizontal well 2 demonstrates the economic impact of not stimulating the bottom 40% of the pay interval. Production was likely also hindered by reduced fracture width (conductivity) near the wellbore as the low stress zones above diverted most of the fluid and proppant away from the wellbore. In addition, the majority of the proppant was placed above the target payzone in severely depleted intervals that are not likely to contribute much production. Using direct fracture mapping diagnostics such as tilt mapping can help you to get subsequent fracture treatments placed where you want them … IN THE PAY!

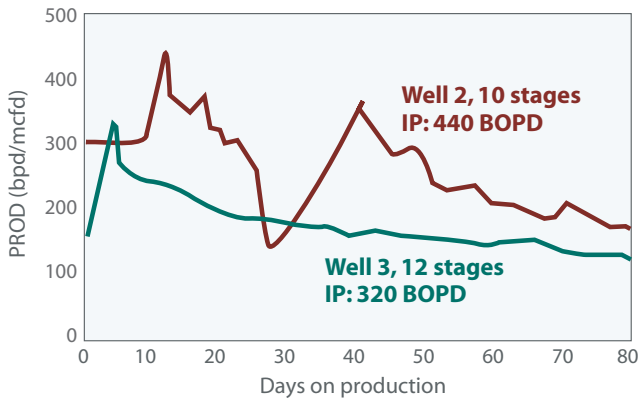


Figure 4. Production response for multi-stage horizontal well 2 and 3. Despite more stages completed in well 3, production response was significantly lower due to a lack of payzone coverage in this well.

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