SPE 39919

Surface Tiltmeter Fracture Mapping Reaches New Depths - 10,000 Feet and Beyond?

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Abstract

Recent improvements in tilt measurement techniques have greatly enhanced the resolution of hydraulic fracture-induced tilts, resulting in both greater mapping precision and an increase in the maximum mapping depth achievable with a surface tiltmeter array. With a previous depth limitation of around 6,000 ft., surface tiltmeter mapping was limited to areas with relatively shallow production. Application is greatly broadened now with a depth range down to 10,000 ft. In addition to the expanded depth range, there has been a marked improvement in the fracture mapping resolution.

This paper begins with an overview of the tiltmeter fracture mapping concept, highlighting both the strengths of this technique and its limitations. Following that is a description of the technical advancements made over the last three years to allow fracture mapping at far greater depths. Finally, two brief case studies are presented to demonstrate fracture mapping at great depth, and also to provide insight on hydraulic fracture growth behavior in two different environments. As the case studies make clear, fracture growth is far more complex than is generally assumed. Better understanding of these complexities can lead to significantly enhanced fracture stimulation practices.

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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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 2 1/2-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.

SPE 49193

Downhole Tiltmeter Fracture Mapping: A New Tool for Directly Measuring Hydraulic Fracture Dimensions

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Abstract

A new fracture diagnostic technology for mapping hydraulic fracture dimensions is introduced: downhole tiltmeter fracture mapping. Downhole tilt fracture mapping involves deploying wireline-conveyed tiltmeter arrays in offset wellbores to measure hydraulic fracture growth versus time. This technology has been employed to map over 100 fracture treatments in the last eighteen months. Allowing, for the first time, the gathering of statistically significant data-sets on how hydraulic fractures actually do grow - albeit, within only a few fields so far. In addition to providing fracture diagnostic data (fracture length, height, width and asymmetry), this new capability allows enhanced utilization of hydraulic fracture models because model predictions can be "calibrated" with insitu observations of fracture growth.

The mapping concept is quite simple: creating a hydraulic fracture involves parting the rock and deforming the reservoir. Downhole tiltmeter mapping involves measuring the fracture-induced deformation in a nearby offset well(s) versus time and depth and inverting the data to obtain the created fracture dimensions. The principles are the same as for surface tiltmeter mapping, but the different array geometry make it very sensitive to fracture dimensions and less sensitive to fracture orientation - just the reverse of surface tiltmeter mapping. This paper will explain the fundamental concepts, the implementation strategy (wireline arrays, processing and modeling), present three field case studies, and briefly discuss the implications on fracture modeling.

SPE 54079

Fracture Growth and Reorientation in Steam Injection Wells

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Abstract

Conventional wisdom regarding fracture orientation 1 of steam fractures is that they grow along the same orientation as "typical" propped fracture treatments - i.e., perpendicular to the least principle stress direction. However, direct measurements (utilizing surface tiltmeter fracture mapping) show that the orientation of steam-induced fractures is very different from propped fractures. Steam fractures have been observed to grow predominantly along two distinct planes that are oriented 45° with respect to the preferred fracture plane. These two planes coincide with the planes of maximum shear stress. Steam fracture reorientation toward these two planes has thus far been directly observed in the South Belridge, Lost Hills, and Cymric Fields in the San Joaquin Valley in California.

The measured data also shows that the fracture orientation is sensitive to the injection rate. Above a "critical" rate (which most likely depends on horizontal stress bias, shear frac conductivity and fluid viscosity) fractures grow perpendicular to the minimum principle stress. Below this critical rate, however, fracture growth is along the two distinct maximum-shear orientations. Steam injection wells are especially vulnerable, as steam injection rates are generally low in comparison to propped fracture treatments. The proposed mechanism for steam fracture reorientation that we present in this paper is pore pressure elevation along a direction of enhanced permeability along shear fractures ahead of the fracture tip, which causes the preferential fracture growth direction to change along the direction of maximum shear stress.

Although fracture reorientation can provide an increase in reservoir access and production rates in areas where the "huff and puff"-technique is used, reorientation is detrimental for steamfloods, as "short-circuiting" may result and reserves may be bypassed.

Introduction

In recent years, coffee houses have demonstrated the power of steam, as they thrived by the hissing sounds of their steam generators. Steaming is also very much in fashion in the oil industry, where thermal recovery is the most significant enhanced-oil-recovery (EOR) method. In California, for example, over 2.3 million BWPD is injected as steam, and thermal recovery accounts for 420,000 BOPD, almost 50% of the state's total production. Generating steam can be very powerful and beneficial indeed, and the resulting dark brown fluid is well worth it.

Steam injection is required in heavy oil reservoirs, such as the Midway-Sunset and Cymric Fields in California, to obtain economic oil production. Generally, this is implemented using a steamflood or a "huff and puff" (injecting into and producing from the same well) strategy. Steam injection is also implemented to improve ultimate oil recovery in maturely developed oil fields, such as the South Belridge and Lost Hills Fields in California. Most of these fields have traditionally been developed with primary production through propped fractures. Well patterns for primary production have been optimized by directly measuring fracture azimuth, mostly by utilizing surface tiltmeter fracture mapping. Optimization of the well pattern for thermal recovery projects in both "huff and puff" and line drive requires accurate knowledge of the fracture orientation (fracture azimuth and fracture dip).

SPE 56724

Understanding Hydraulic Fracture Growth: Tricky but Not Hopeless

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Abstract

Hydraulic fracturing has proven to be a fruitful well stimulation technique in an ever-increasing range of environments. Application has spread from the original target of enhancing production rates from low permeability reservoirs to fracturing of poorly consolidated high perm reservoirs, fracturing of horizontal and deviated wellbores, fracturing of unconventional (often naturally fractured) reservoirs, fracturing for waste disposal, etc. While significant progress has been made in engineering hydraulic fracturing treatments, we are still often humbled and alarmed by the apparent complexity of the process.

This paper does not present "the answer" to this complex problem. Instead it attempts to shed some light on areas where we must be careful with our assumptions. This paper presents examples of measuring (inferring) hydraulic fracture growth in a number of different environments. For each example we discuss the implications of the observed fracture growth. For example, how accurate were the fracture model predictions? How effective is the current completion / fracturing strategy in achieving the design goals? What are we learning about the factors or mechanisms that govern hydraulic fracture growth? How can these new insights aid production enhancement?

While most of the direct observations of hydraulic fracture growth are from downhole-tilt fracture mapping, data from many additional diagnostics are also included (post-frac logging, production response, intersections with offset wells, microseismic mapping, etc). Perhaps the most surprising observation is the observed range of fracture height growth: spanning from well-contained fractures in the absence of significant formation stress barriers, to extremely uncontained fracture height growth. Observations of fracture width, length, and asymmetry will also be presented and discussed.

SPE 59525

Identification and Implications of Induced Hydraulic Fractures in Waterfloods: Case History HGEU

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SPE 2000

Abstract

In secondary and enhanced oil recovery projects, it is critical to determine if hydraulic fracturing occurs during water injection and, if fracturing occurs, to understand its associated impacts on oil recovery. If hydraulic fracturing occurs under normal injection operating conditions or, if the production and/or injection wells are fracture stimulated, knowing the orientation and dimensions of the created fractures are critical for determining the proper pattern alignment to optimize sweep efficiency. This paper presents the application and results of tiltmeter mapping techniques used at the Howard Glasscock East Unit (HGEU). Tiltmeter mapping was used to determine the existence, orientation, and geometry of created hydraulic fractures, as well as, the dependence of fracture length on the water injection rate. Tiltmeter fracture mapping identified that hydraulic fracturing occurs even at very low water injection rates (less than 250 BWPD) at the HGEU creating significant fractures (exceeding 400 feet of half-length). The mapping also showed that the length of the fractures was relatively rate independent over the range of rates tested. The HGEU waterflood pattern orientation, pattern spacing and injection rate guidelines were established based on these results.

Introduction

The Howard Glasscock East Unit produces from multiple formations in the Howard Glasscock Field of West Texas. Prior to this work, a portion of the Unit was under pilot waterflood operations in the Seven Rivers, Queen and San Andres formations using 40-acre inverted 9-spot patterns. The Seven Rivers and Queen are sandstone formations and the San Andres is a carbonate formation. It was determined that the initial water injection scheme was insufficient to effectively waterflood these formations and would need to be altered as the waterflood was expanded to the entire Unit.

It is has been documented that hydraulic fractures can improve areal sweep efficiency if the waterflood patterns are properly aligned.1,2 In many cases, directional permeability in reservoirs has been directly attributed to fracturing (both natural and induced).3,4 If the waterflood patterns are not aligned properly, the waterflood will be adversely affected, especially if the fractures are long relative to the well spacing.5,6 These adverse effects are shown to increase as the mobility ratio increases, as typically seen in EOR projects.

Evaluations were undertaken at the HGEU to insure that the waterflood would not be adversely effected by possible fracturing in the water injection wells and to determine if the water injection rates could be increased. As part of this evaluation, the following critical questions were put forth:

Are hydraulic fractures being created at the current water injection rates and pressures?

If present, what are the azimuths of the created fractures (both for the waterflood-induced fractures in the injection wells and for the propped fracture treatments in the producing wells)?

What are the hydraulic fracture lengths and are they different for different water injection rates?

What is the fracture geometry for the propped fracture treatments in the producing wells?

Are these fracturing issues different for the sandstone (Seven Rivers and Queen) and the carbonate (San Andres) formations?

Tiltmeter mapping techniques, incorporating both surface and downhole tiltmeter arrays were effectively employed in both the active waterflood and un-waterflooded areas to answer these questions.

SPE 59735

Diagnostic Techniques to Understand Hydraulic Fracturing: What? Why? and How?

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Abstract

In recent years there have been numerous advances in fracture mapping/diagnostic technologies. This paper details the state-of-the-art in applying both conventional and advanced technologies to better understand hydraulic fracturing and improve treatment designs. The initial portion of the paper describes the application and limitations of various diagnostic tools and methods, including well testing, net pressure analysis (fracture modeling), techniques that employ open-hole & cased-hole logs, surface & downhole tilt fracture mapping, microseismic fracture mapping, and production data analysis. The bulk of the paper is dedicated to case histories that illustrate the application of these various fracture diagnostic technologies. The case histories include examples of how several fracture diagnostics can be used in concert to provide more reliable estimates of fracture dimensions and allow better economic decisions.

Introduction

The process of hydraulic fracturing has always had a "black box" image. This has been partly because knowledge about fracture geometry is difficult to obtain with fractures growing thousands of feet below the surface, and partly because fracturing is proving to be vastly more complex than initially thought.1-3 While hydraulic fracture treatments continue to be designed using the best tools and techniques available, geometry estimates from fracture models have been difficult to verify. Numerous fracture diagnostic techniques have been developed to fill this knowledge gap, improving our understanding of hydraulic fracture behavior.4-10

The main purpose of fracture diagnostics is to help the producer optimize field development and well economics. This can include optimizing individual fracture treatments to obtain the most economic design and optimum interval/height coverage or optimizing the entire field development in terms of well spacing and location. Fracture diagnostics can be beneficial in numerous stimulation settings. Settings range from propped fracture stimulation of a new pay zone in a newly developed field to infill-drilling development, and from field development using hydraulically fractured horizontal wells to the evaluation of fracturing during steam-flooding or water-flooding.

When executing fracturing operations in one of these settings, several questions can be answered in the design/evaluation process using fracture diagnostics, including:

Do fractures effectively cover the pay zone?

Are fractures confined to the pay zone?

Does the fracture grow into an unwanted gas bearing or water-bearing zone?

What is the optimum number of fracture treatment stages and treatment size to cover thick pay zones?

How much more length/height/production is obtained if treatment size is increased?

Is the final fracture conductivity sufficient to achieve the desired production? What is the optimum proppant?

Is the hydraulic fracture oriented in the same direction as the primary set of natural fractures?

What direction should a horizontal well be drilled to complete it with transverse (or longitudinal) multi-stage fracture treatments?

Is the well pattern appropriate to maximize sweep efficiency in steam/water-flood areas?

Do the injected waste and drill cuttings remain within the selected zone?

Numerous fracture diagnostics are available (see Figure 1), including techniques that directly image "big picture" far-field fracture growth, dimensions, and orientation; tools that provide a local measurement of the fracture at the wellbore; and lower-cost indirect (model-dependent) diagnostic methods. There are three main groups of commercially available fracture diagnostic techniques, each with their own set of capabilities and limitations. A summary of the techniques, limitations and the parameters each technique measures is provided in Table 1.11

SPE 59715

Tiltmeter Hydraulic Fracture Mapping in the North Robertson Field, West Texas

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Abstract

This paper presents both downhole and surface tiltmeter hydraulic fracture mapping results of five fracture treatments (in two wells) in the Clearfork formation located in the North Robertson Field, West Texas. This field is under waterflood and both injectors and producers are generally fracture treated in three stages at depths of roughly 6,000 to 7,100 feet. Surface tiltmeter mapping was performed on all five treatments to determine hydraulic fracture azimuth and dip. Downhole tiltmeter mapping was performed on 2 treatments in one well to determine the fracture geometry (height and length). In addition, other diagnostic technologies such as fracture modeling and radioactive tracers were used and their results and conclusions are discussed in conjunction with tiltmeter mapping. Understanding hydraulic fracture growth is of critical importance for evaluating well placement and the risk of communication between producers and injectors and to assess fracture staging, perforating and well performance issues.

Introduction

The North Robertson field is under waterflood and both injectors and producers are generally fracture treated in three stages. The target zones were the oil-producing Lower, Middle and Upper Clear Fork carbonate formations at depths of roughly 6,000 ft to 7,100 ft. Knowing the azimuth, dip and geometry of hydraulic fractures is critical for evaluating well placement strategies for waterflood applications. Surface and downhole tiltmeter fracture mapping are technologies that provide these important measurements of fracture azimuth, dip and geometry1-6. Tiltmeter fracture mapping has previously shown that fracture azimuth and dip can change dramatically in waterflood areas due to local variations in reservoir pressure5. This can result in hydraulic fracture reorientation that can cause waterfloods to "short circuit", thereby significantly reducing sweep efficiency. This paper demonstrates how tiltmeter fracture mapping technology was used to:

1. Measure the hydraulic fracture azimuth, dip and geometry to evaluate the risk of communication between producers and injectors,
2. Quantify hydraulic fracture geometry to understand the performance of both producers and injectors,
3. Calibrate hydraulic fracture models to optimize fracture treatments, and
4. Evaluate the effect of perforating schemes on fracture geometry and staging.

The project included two wells. The NRU 1514 was fractured in three stages, and the NRU 3019 in two stages. Surface tiltmeter mapping was performed for all stages on both wells. Downhole tiltmeter mapping was performed on two stages in the NRU 1514.
All treatments used 20 to 25 lbs/Mgal crosslinked gel, and about 600 bbls clean volume containing 70,000 lbs of 20/40 sand (2 to 8 ppg ramp) pumped at about 30 bbls/min.

Tiltmeter Mapping to Monitor Drill Cuttings Disposal

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Abstract

This paper documents the preliminary results of the application of surface and downhole tilmeter diagnostics to map, monitor, and evaluate downhole drill cuttings disposal at the joint-industry Mounds Drill Cuttings Injection Field Experiment Project. Knowledge of the created hydraulic fractures was critical for determining the placement of core-through wells to evaluate the "disposal domain" or fracturing mechanisms for both sandstone and shale intervals. Through real-time monitoring of the fracture geometry it was possible to detect fracture height growth during the test and insure that the injected fluids stayed in the intended zone. Also presented is a novel approach for determining fracture closure stress using downhole tilt analysis. The implications for hydraulic fracturing growth modeling are addressed.

SPE 62577

Precise Tiltmeter Subsidence Monitoring Enhances Reservoir Management

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Subsidence monitoring is most commonly conducted using either level surveys or GPS surveys of elevation across a field as a result of injection and production activities. Several operators near Bakersfield, CA are using tilmeter-based subsidence monitoring to obtain highly detailed maps of subsidence with continuous data acquisition. The tiltmeter measured subsidence is then correlated to production and injection on a day-by-day basis so the impact of individual injection and production events can be quantified. The data is presented in a video format that allows visual assessment of the field motion. In some fields, the monitoring array is also equipped with monuments for periodic level survey and GPS measurements of the ground motion.

This paper discusses the design and installation of tilmeter subsidence monitoring arrays and the format of the results. In addition, the subsidence data is correlated to field activities to show how the monitoring can be used to correlate ground movement with reservoir events.