FRACTURE CHARACTERIZATION A KEY FACTOR IN YATES STEAM PILOT DESIGN AND IMPLEMENTATION

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Abstract
The successful design and implementation of any improved oil recovery project in a fractured reservoir depends on an accurate characterization of the fracture system. This is especially true in a steam pilot project currently underway in the Yates Field of West Texas. This pilot will assess the economic viability of accelerating gravity drainage in the gas cap of the fractured San Andres reservoir. From the conceptual phase of the project through implementation and monitoring, fracture characterization in the pilot area has been critical to pilot design and success. Key decisions have depended on an accurate assessment of fracture density, orientation, flow capacity and connectivity to other portions of the reservoir. Many geologic and engineering methods have been employed to understand the fracture system. Flexure mapping, tracer testing, pressure interference testing and reservoir simulation were employed in the design phase of the project. Fluid sampling and passive microseismic monitoring have been employed to monitor the project. This paper will discuss each **of** these methods, field results, and key decisions that were based on the analyses.

Introduction
The Yates Field is located at the southern tip of the Central Basin Platform in the Permian Basin of West Texas (Figure 1). The majority of production comes from a series of stacked carbonate shoals in the San Andres formation at an average depth of 1500 feet'. Reservoir quality dolomite in the Yates Field has average porosity of 15% with average matrix permeability of 100 millidarcies. Reservoir flow is dominated by fractures caused by deformations and surface exposure in the geologic past. Fracture porosity averages 2% with permeabilities exceeding 1 darcy. The dominant mechanism for oil recovery is gravity drainage, employing the Double Displacement Process. This process has been defined' as the gas displacement of a water invaded oil column. At Yates, nitrogen gas is injected into the reservoir to recover more oil by expanding a gas cap and allowing gravity drainage of liquids to occur.

A steam pilot was initiated in December **1998** to assess the economic viability of improving the vertical gravity drainage process. This pilot, implementing the TAGS (Thermally Assisted Gravity Segregation[3]) process, is unconventional in a number of ways. The pilot utilizes innovative treating processes to generate steam from poor quality produced water[4]. Steam is injected into a fractured secondary gas cap at high rates, not as a displacing agent, but to heat oil, reduce viscosity and improve gravity drainage from dolomite matrix toward highly conductive fractures. Oil mobilized due to steam injection drains vertically to the oil column, then laterally via fractures to offset producers (see Figure 2). Economic viability will ultimately depend on the incremental oil production due to steam injection versus project costs.

Many issues arise in the design and implementation of an EOR project of this type, which ultimately depend on an accurate characterization of the fracture system. Issues in the design phase include the location of the steam pilot, the rate of steam injection into the gas cap, the number of injectors required to achieve this rate and the ultimate placement of these steam injectors. Once the project is implemented, a successful monitoring program depends on an understanding of how steam and heated fluids will move through the reservoir. Poorly positioned monitoring wells that lack communication with the fracture system are not only expensive, but may not provide critical data necessary for an economic assessment of the project.

Many geologic and engineering tools were employed throughout the course of the project. This paper will now focus on these tools, how and when they were used and key decisions that were based on their analysis.

Pilot Location and Early Fracture Understanding
The most important decision made in the conceptual phase of the project was the location of the steam pilot within the Yates Field. To assess economic viability, the steam pilot had to be located in a highly fractured portion of the reservoir, where high steam injection rates could produce a timely oil production response. Early field data and innovative use of this data provided insights into fracture density and flow capacities essential for positioning the steam pilot.

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Field Data.

As the Yates Field was developed, great amounts of data were gathered which, when used collectively, helped to identify and characterize dominant flow features on a broad scale[5]. Caliper and density correction data, mud logs, image logs, cores, drill stem tests, spinner profiles and production and injection data were all used to form an understanding of major flow features and directional permeability trends in the Yates Field.

Mapping and Drilling.

Fracture understanding was advanced significantly with the work of Tank et al 1997[6]. Enhanced flexure (second derivative) mapping of formation tops indicated the location of strain zones within the field possessing a high probability of massive fracturing (Figure 3). These zones were confirmed with data provided by the drilling of over 100 short radius horizontal wells between **1986** and **1996.**

Pilot Location.

Based on this mapping and drilling, as well **as** the collective data described above, the location of the pilot was chosen in a northwest portion of the field known as Tract **17. A** fracture model was developed for this pilot area using all available data (Figure 4). Major flow features were modeled deterministically, while less intense, more dispersed background fractures were modeled stochastically. This model was then tested for reasonableness by various engineering tools.

Tracer Testing

Past carbon dioxide (CO_2) injection breakthrough and sodium bromide (NaBr) tracer tests were analyzed to evaluate fluid movement in the pilot area. These analyses verified the fracture characterization derived by geologic methods and confirmed a strong northwest to southeast **(NW-SE)** flow directionality. CO_2 injection in **1986** in well 17B5 provided the first tracer test in the gas cap. Figure **5** illustrates the breakthrough times of CO_2 observed in offset producers. Breakthrough times ranged from 1 to 12 months, with faster breakthrough observed in a NW-SE direction. NaBr tracer was injected into a water injector, well 1711, in **1996.** Figure **6** illustrates breakthrough times of NaBr observed in offset producers. Breakthrough times ranged from 3 days to 10 months and again suggested a strong NW-SE direction of flow. These breakthrough times were later used as a match parameter in a reservoir model to increase confidence in the fracture interpretation.

Pressure Interference Testing

Further confirmation on flow directionality was provided by pressure interference tests in the pilot area. Pressure data was recorded in one well, the **1703,** while eight offset wells were pulsed at varying times. Analysis of the data indicated a flow direction of N72°W across the pilot area (see Figure **7).** The total mobility along this direction was **838,400** md/cp, while the minimum mobility (normal to the maximum mobility) was **54** md/cp. While the exact flow direction was biased by wellbore selection, the 16,000:1 contrast was meaningful to confirm the strong NW-SE directionality observed in tracer tests.

Conventional Reservoir Modeling

Once fracture properties were determined by geologic and engineering methods, reservoir simulation was used extensively to investigate the reasonableness of these fracture properties. **A** model was built that sought to match historical production and injection data, pressure data, and contact movement data by adjusting fracture properties. This model confirmed the reasonableness of the fracture properties and was then used to match the tracer testing performed in **1996.** Figure **8** illustrates tracer movement in three dimensions through the model at different times. This movement matches the breakthrough of tracer in the field test as shown in Figure **6.**

Thermal Reservoir Modeling

Once the fracture network had been characterized for flow behavior and tested through conventional reservoir modeling, a specialized thermal model was constructed to investigate critical issues facing the steam pilot. Reservoir simulation' of the thermal process directed the implementation of the steam pilot by providing insight into: 1) the steam rate necessary to stimulate timely thermal response from the project area, ***2)*** the number of steam injectors necessary to achieve this steam rate, 3) the placement of steam injectors to intersect major flow features and ensure injectivity, and **4)** the expected oil rate from steam injection. **All** of these critical issues depended on an accurate characterization of the fractures. Figure **9** illustrates temperature changes within the thermal model at different times. These temperature changes highlight the influence the fracture network will have on heat distribution in the reservoir as steam is injected.

Steam Pilot Implementation

Implementation of the steam pilot commenced in 1997 with the construction of water treating facilities and the drilling of steam injectors. A well status map of the steam pilot after implementation is provided in Figure 10. Five steam injectors were positioned in the pilot area and drilled horizontally to encounter major fracture flow features identified by the fracture model. Steam injectors were designed based on an understanding of fracture connectivity. Since there was high confidence from fracture characterization and modeling that the reservoir would not be a limiting factor in injectivity, casing and tubing strings were optimized to reduce costs by providing only the required injection rates. Steam injection was initiated on 12/28/98 at design rates and has continued with no reservoir limitations.

Observation Well Positioning

Based on an understanding of fracture connections, five fluid contact monitoring wells and two saturation monitoring wells were positioned in the pilot area to provide key information to evaluate pilot performance*. In the case of the two saturation monitoring wells (see Figure 10), it was critical to place these wellbores in the fracture system where they would be in communication with the steam injectors. If these wellbores missed the fracture system, they would likely heat too slowly to observe changes in fluid saturation as a result of steam injection. After **9** months, repeat temperature logs indicate that these wellbores are heating (Figure 11). This demonstrates successful positioning based on characterization of the fractures in the pilot area.

Fluid Monitoring

Fracture understanding was also a key factor in the design of a fluid-monitoring program for the steam pilot. Knowing that massive fractures would allow mobilized fluids to be produced large distances away from steam injectors, a fluid sampling schedule was constructed for wells both inside and outside the pilot area. By monitoring fluid samples along known fracture trends, the movement of fluids outside the project area could be detected. This information is important in evaluating the economic viability of the steam pilot. Figure 12 illustrates the observed changes in oil viscosity in and around the pilot area. This map indicates that thermally influenced oil is indeed being produced outside the project area. Without an understanding of the fracture system, a monitoring program may not have thought to sample fluids on a regular basis so far from the steam injectors.

Passive Microseismic Monitoring

Due to movement of fluids out of the project area, it is difficult to evaluate steam pilot response from production monitoring alone. An independent estimate of mobilized oil is desirable to truly assess economic viability. With an understanding of the fracture trends and how heat would propagate along them, a passive microseismic monitoring project was implemented to assess the shape of the heated zone'. Geophone arrays were cemented in five strategically positioned wellbores to record microseismic events as the rock thermally heats and expands (see Figure 9). Once again, fracture characterization was instrumental in the design and placement of these wellbores. By triangulating microseismic events detected simultaneously by more than one geophone, a time-lapse image of the heated zone can be determined.

Conclusions

1. Many geologic and engineering tools were employed over the course of time to characterize the fracture system in the Yates Field. These tools were employed first on a field wide basis and then to a project area to design and implement a steam pilot for enhanced oil recovery.
2. Key decisions were made in the design phase **of** the project based on the characterization of the fracture system. These decisions ranged from pilot area location to specific design parameters such as steam rates and well positions.
3. Implementation of the steam pilot verified the correctness of the fracture characterization in the project area. Fractures were encountered in the locations they were expected and contained enough permeability to inject the design volumes.
4. Knowledge of the fractures was a key element in the design and implementation of a successful monitoring program in the pilot area.

Nomenclature

md = millidarcies
cp = centipoise

Reference

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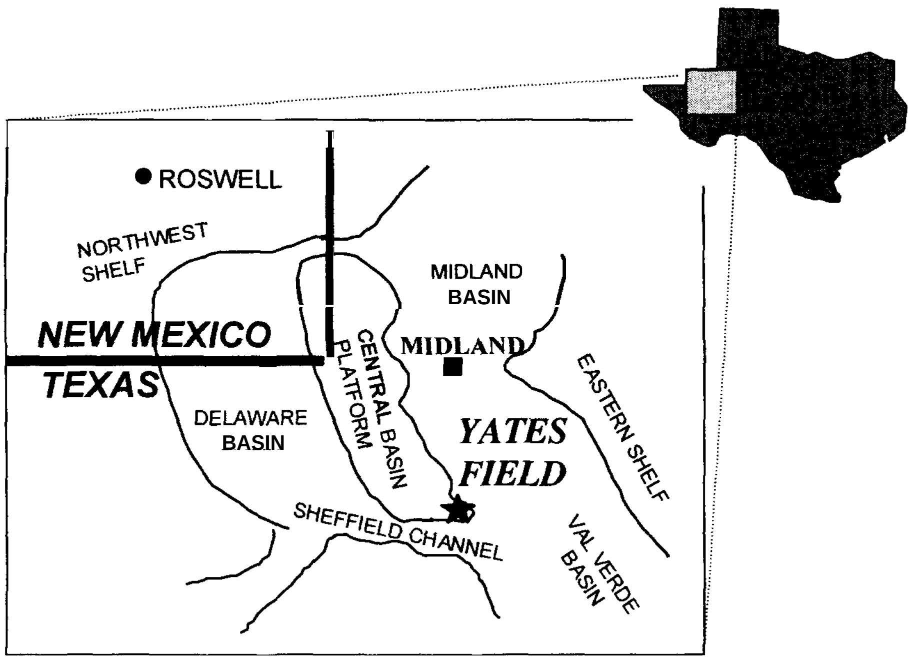


Figure 1 - Yates Field Location at the Southern Tip of the Central Basin Platform, Permian Basin, West Texas

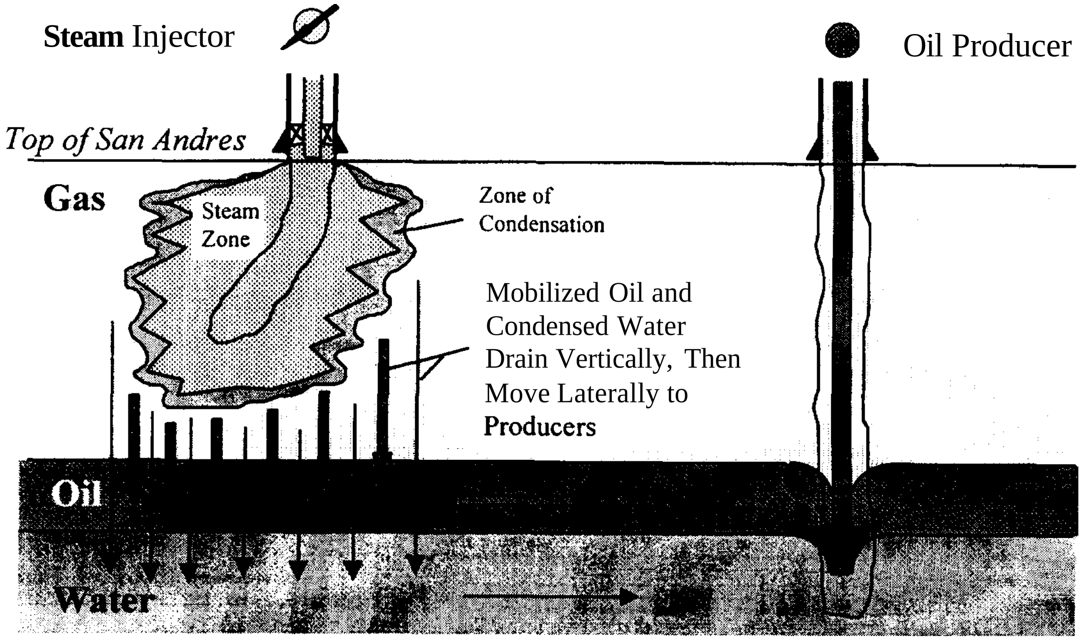


Figure 2 - Schematic of Steam Injection into the Yates Gas Cap
Oil mobilized by steam injection drains vertically to the oil column,
then laterally via fractures to offset producers.

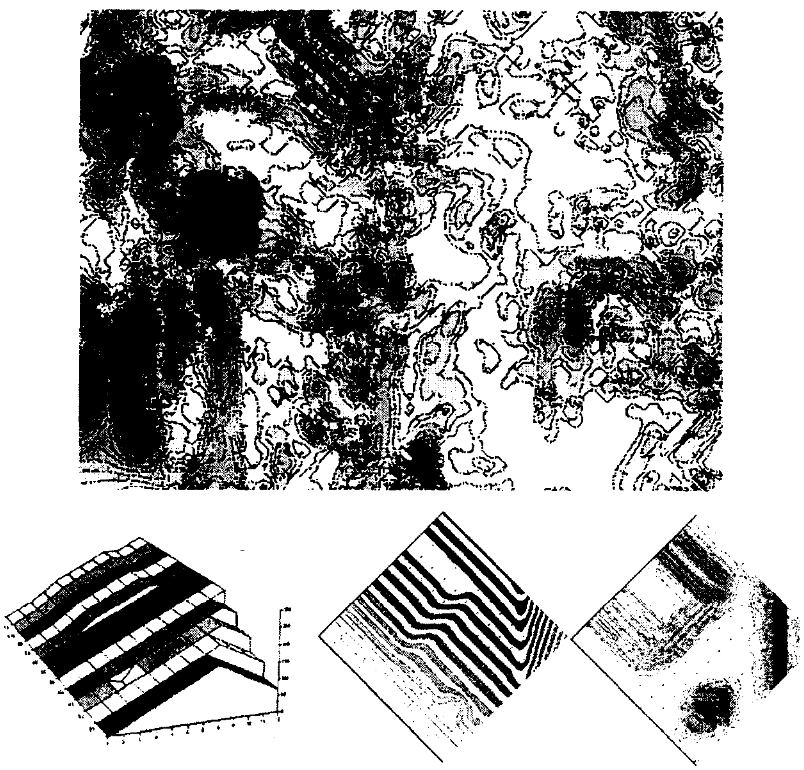


Figure 3 - Illustration of the Development of a Flexure Trend Map
from Structure Data for a Portion of the Field

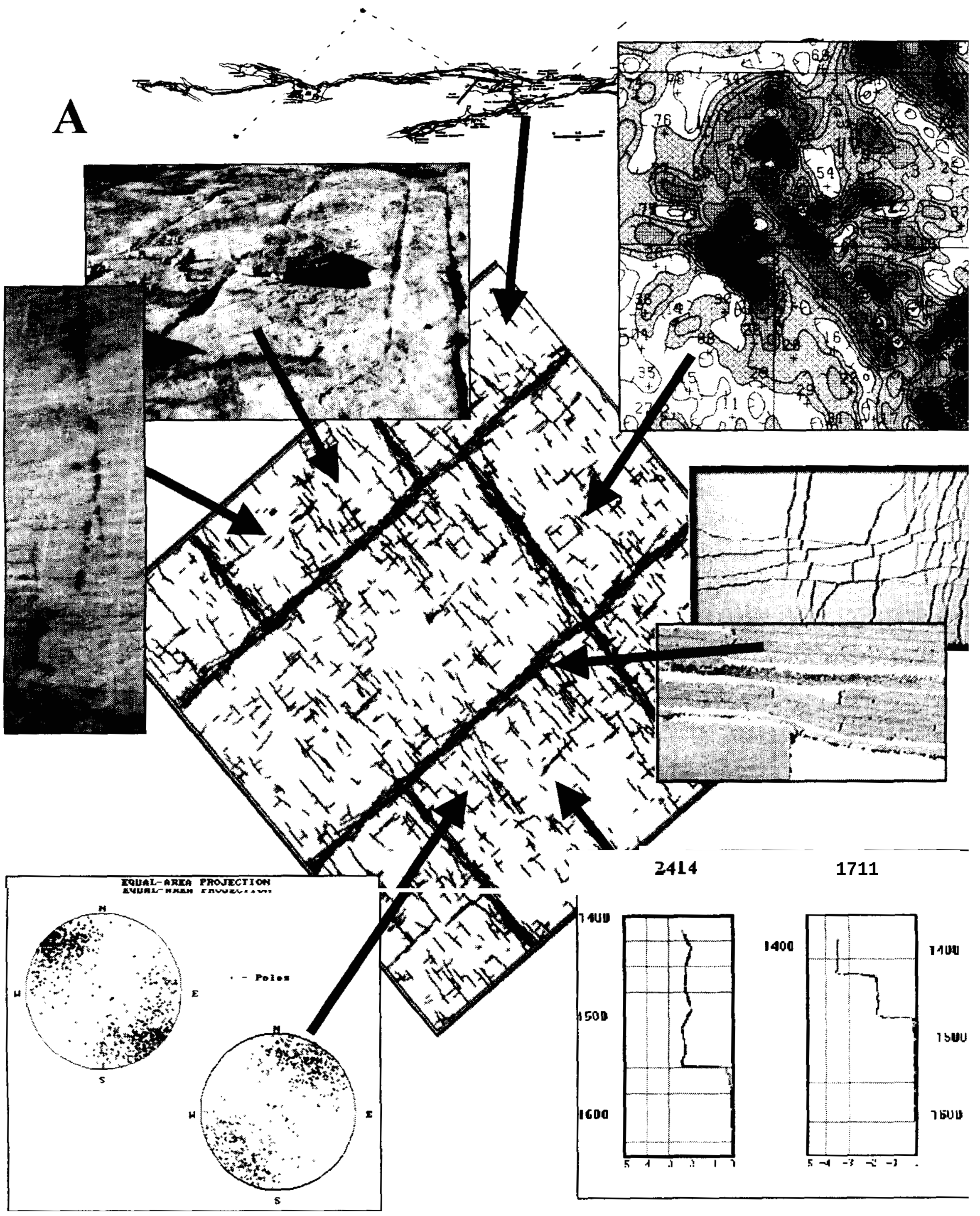


Figure 4 - Development of a Fracture Model for the Steam Pilot Area Using All Available Data
Outcrops (A), cave analogs (B), flexure maps of structure (C), physical models (D),
open hole injection profiles (E), and formation imaging (FMI) logs (F) supported
discrete fracture network (DFN) modeling for which one realization of the
deterministic and stochastic fractures is provided as G.

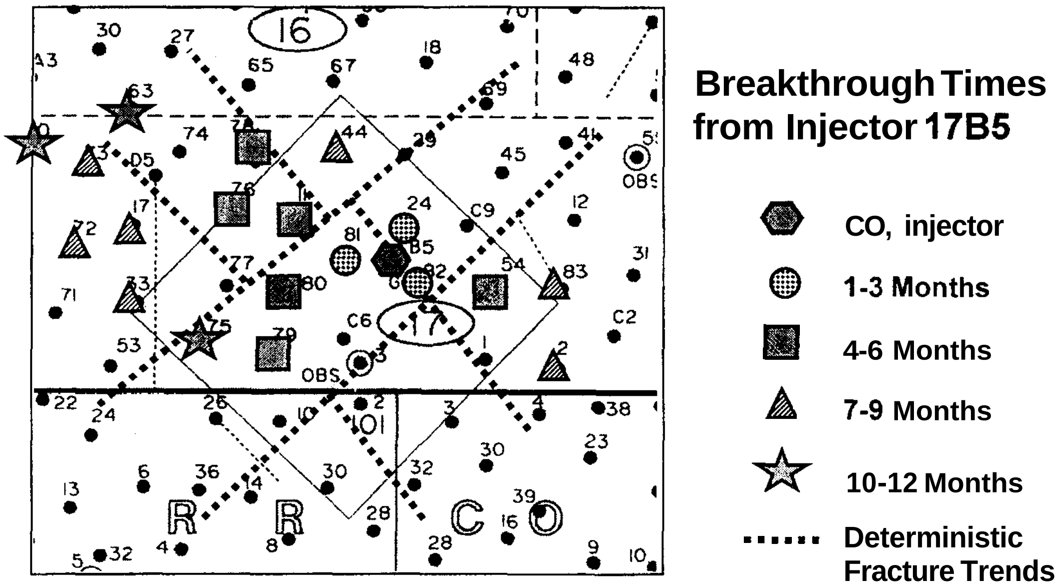


Figure 5 - C02 Breakthrough Was Used to Characterize Fractures Trends in the Steam Pilot Area

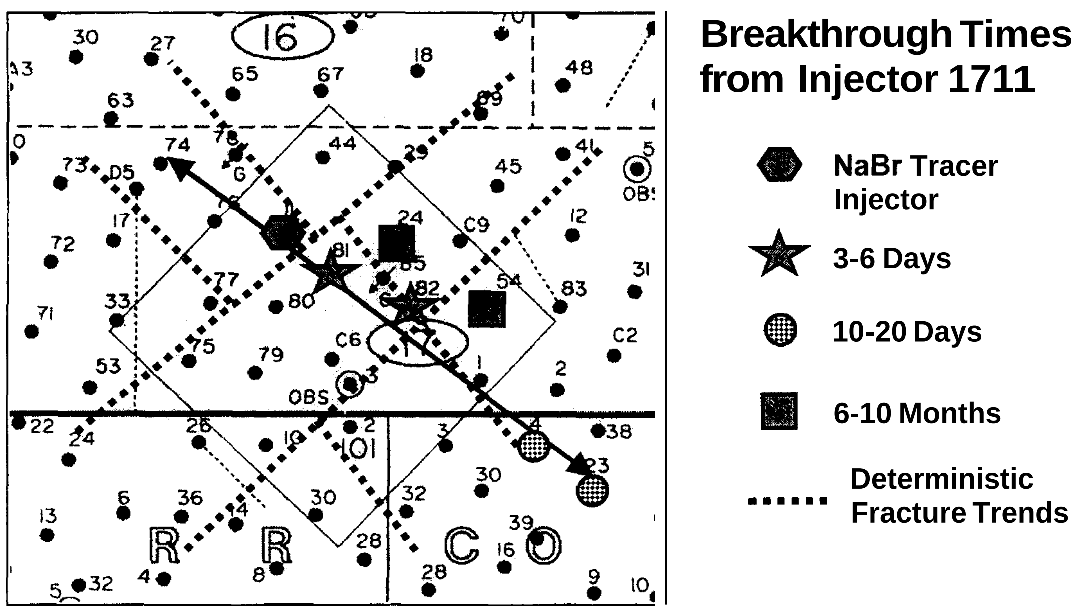


Figure 6 - Tractor Testing Confirmed Major Flow Features in the Northwest-Southeast Direction

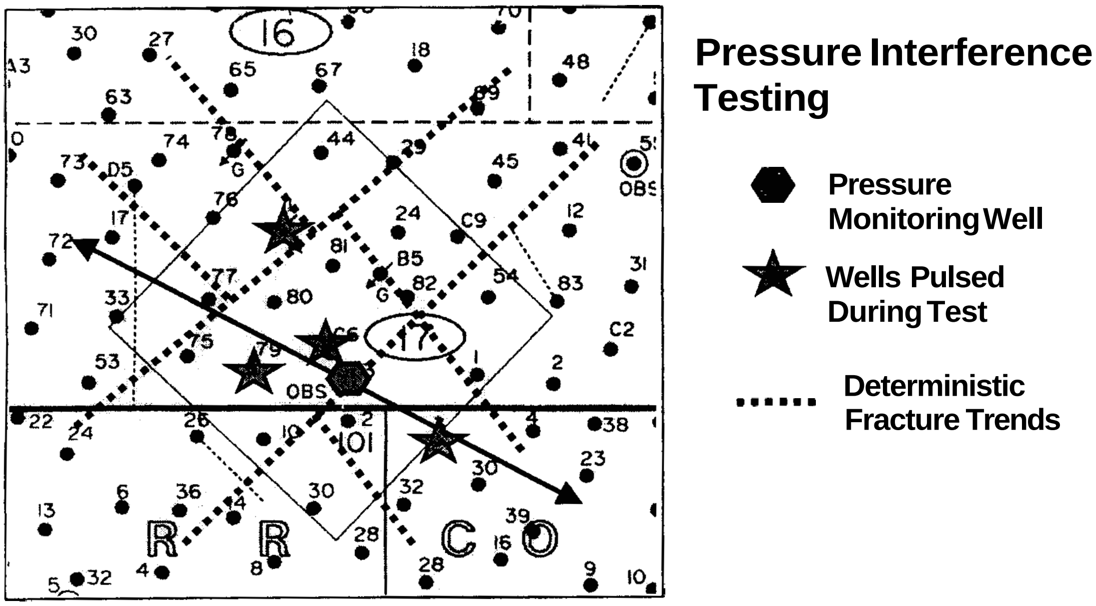
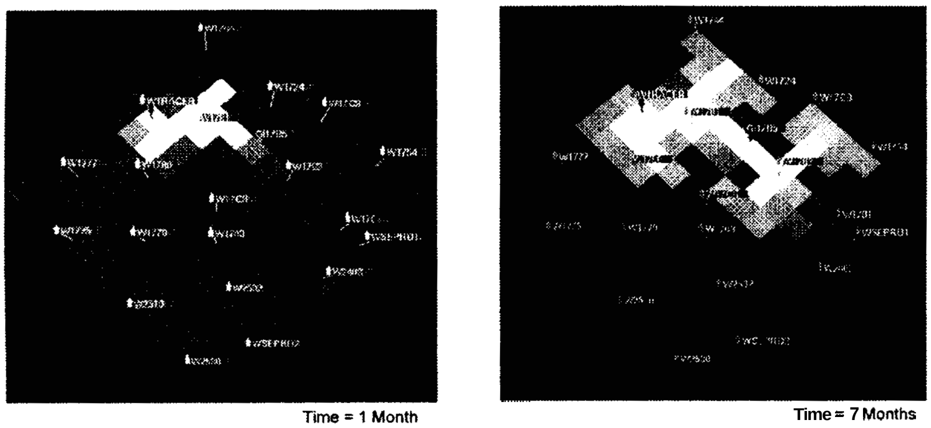
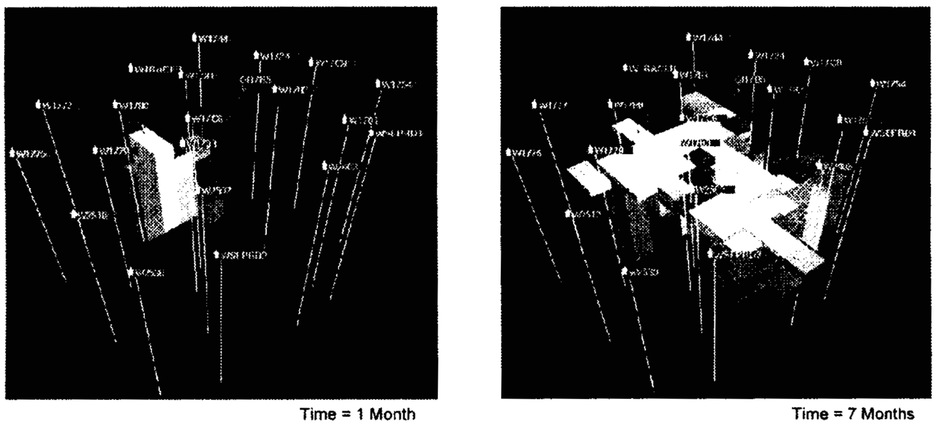


Figure 7 - Pressure Interference Testing Confirmed the Fracture Interpretation in the Steam Pilot Area



Areal View of Model Tracer Concentrations (Lighter Shades Indicate Higher Concentrations)



3-D View of Model Tracer Concentrations (Lighter Shades Indicate Higher Concentrations)

Figure 8 - Conventional Reservoir Modeling to Match Tracer Test Results
Conventional modeling was utilized to confirm the fracture interpretation in the steam pilot area. Model breakthrough times of tracer were matched with actual field results of sodium bromide tracer.

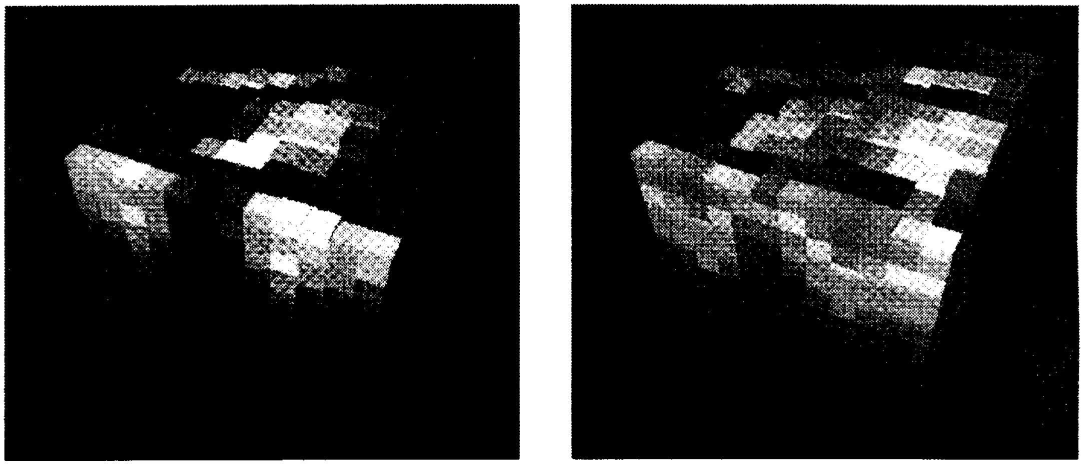


Figure 9 - Thermal Reservoir Model Temperatures at 1 Year and 3 Years of Steam Injection
Model is cut along a fracture trend, where lighter shading reveals heating up to 470°F
(darker cells remain at original temperature -82°F).
Elevated temperature reveals areal and vertical heat movement along fracture trends.

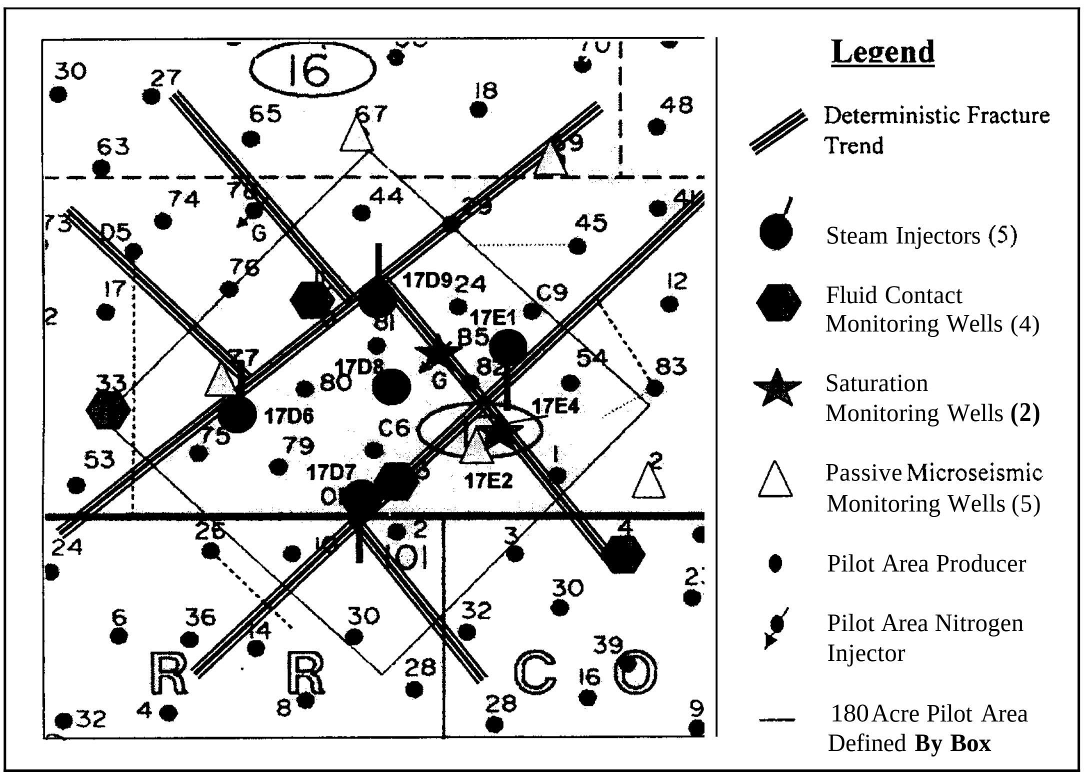


Figure 10 - Yates Steam Pilot After Implementation
A thorough characterization of fractures in the steam pilot area led to the successful
drilling of steam injectors into highly conductive fractures.
Monitoring wells were also positioned based on an understanding of flow directionality.

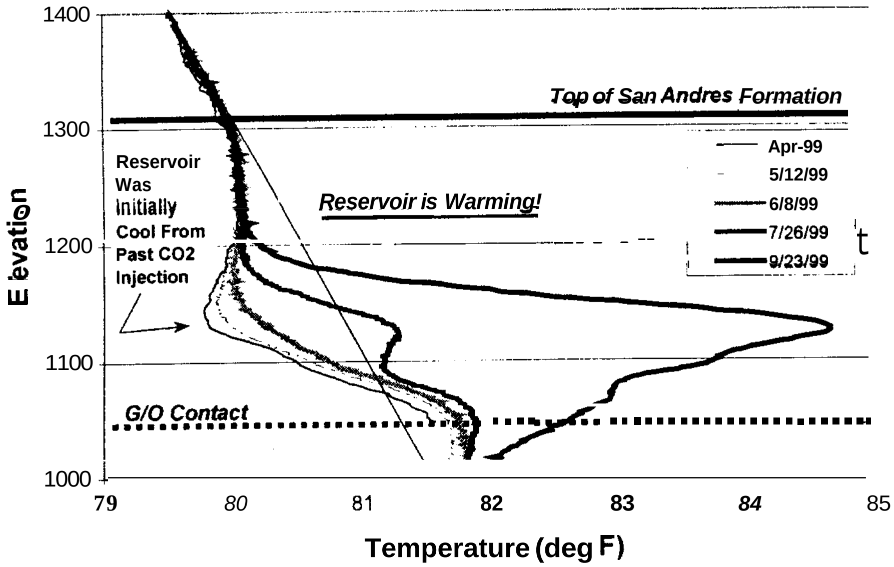


Figure 11 - Time-Lapse Temperature Log on 17E4 Observation Well
Increasing temperature indicates that this monitoring well was
successfully positioned to encounter fractures.

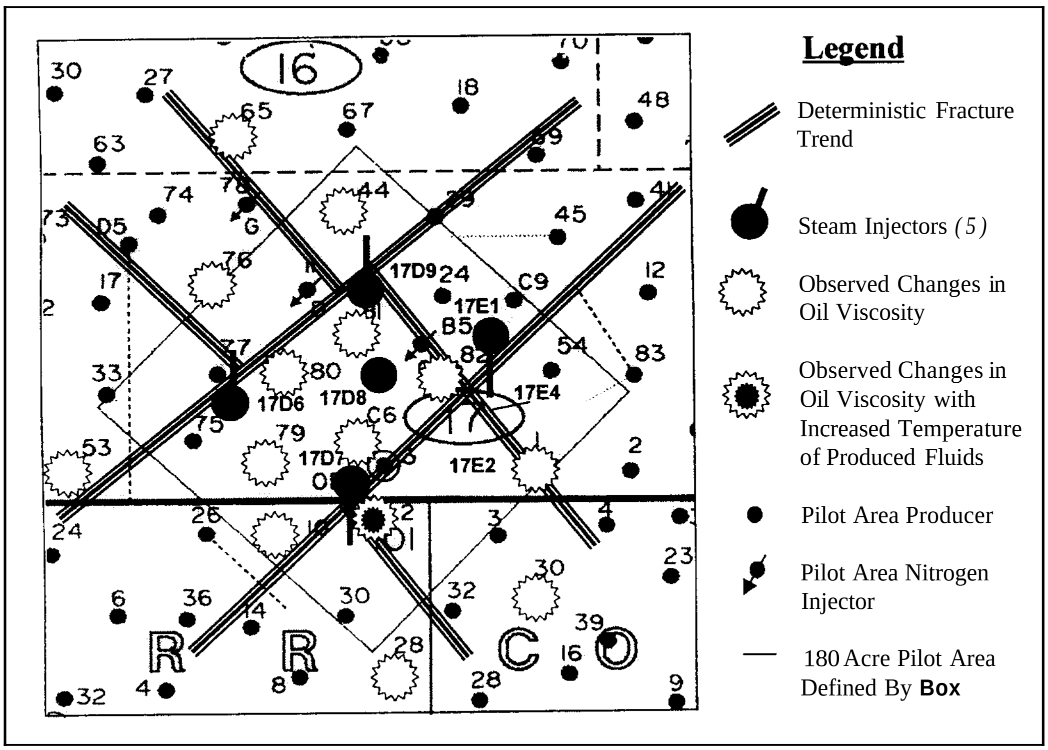


Figure 12 - Observed Changes in Oil Viscosity in the Steam Pilot Area
Oil samples indicate that thermally influenced oil may be moving outside the pilot area.
An understanding of the fracture system was needed to design a fluid
monitoring program to detect this movement.