APPLICATION OF HORIZONTAL WELLS IN WATERFLOOD OPTIMIZATION AT THE NORTH CENTRAL LEVELLAND UNIT IN COCHRAN AND HOCKLEY COUNTIES, TEXAS

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Abstract

A three-well pilot horizontal well program was recently implemented at the North Central Levelland Unit (NCLU) in Cochran and Hockley counties, Texas. Short radius technology was utilized to drill two injection wells and one producer. Horizontal lateral length ranged from 500' to 700'. Primary objectives of the program were to increase injection and production rates and increase waterflood sweep efficiency. Horizontal technology could also be instrumental in improving the economics of a future carbon dioxide (CO2) flood.

This paper discusses the theoretical reasons for drilling horizontal wells at NCLU as well as the actual drilling and completion of the wells.

Introduction

The principle technical challenge in producing secondary and tertiary oil from tight carbonate formations is overcoming the adverse affects of a low average permeability. Low permeabilities result in low injection and production rates in waterfloods as well as CO2 floods. An enhanced oil recovery (EOR) project with low injectivity will usually recover oil at a low rate and will not realize its economic potential; however, artificially forcing a high injection rate will lead to fracturing and subsequent bypassing of target oil through a reduction in areal and vertical sweep efficiency. Horizontal well technology promises to improve recoveries and rates in both waterfloods and CO2 floods, thus reducing response times and increasing economic potential.

Horizontal wells have been used in EOR applications but their use has been widely limited to production wells and thermal EOR. The objective was to develop horizontal well technology for low permeability waterfloods and potential CO_2 floods.

The North Central Levelland Unit is an excellent test case for horizontal well technology for a number of reasons. The pay zone is relatively homogeneous, only 30' thick, and covers an area of 12,000 acres. Additionally, the field contains over 150 patterns drilled on 20-acre spacing. This provides many excellent candidates for the test as well as great potential for field wide application. Also, the low permeability, large reserve capacity carbonate provides substantial unswept reserves to target in the application. Lastly, it is a 25 year old waterflood with a well documented field performance.

The purpose of this pilot project was to drill three horizontal laterals (two from existing wellbores) to accomplish four tasks:

1) Increase injectivity and producibility
2) Contact unswept oil
3) Enhance reservoir conformance
4) Improve CO_2 viability

Background

The North Central Levelland Unit is located in Cochran and Hockley counties, Texas. The unit is being waterflooded and contains 331 active producing wells and 146 active injection wells. Waterflood activities commenced in 1971 shortly after unitization. Production rates are 4600 bopd and 19,000 bwpd. The water injection rate is 26,000 b/d.

The reservoir is located in the lower San Andres Formation of Permian (Guadalupian) Age. In the Levelland area, the lower San Andres Formation is composed of four porosity units, of which the third is productive across the unit. The fourth porosity unit is locally productive. Figure 1 is a compensated neutron-lithodensity log showing the log character of these porous units. The third porosity unit, named in-house the Third Slaughter Marine, is composed of dolomite with intercrystalline porosity (average of 10% porosity) and less than 1 md of permeability. It overlies and is overlain by anhydritic dolomite with a permeability of less than 0.1 md. The overlying porosity units, the First and Second Slaughter Marine, are thief zones at NCLU.

Preliminary Analysis: Steady State Predictions

When a horizontal well is drilled in an existing waterflood, the subject pattern will pass through two stages of development - infinite acting or transient flow, followed by steady state flow when the pressure in the pattern has reached a fixed, stabilized value. Although it is possible to encounter transient conditions which last years under the right conditions, only two months of infinite acting flow was expected at NCLU. Under these circumstances the critical predictive method is one derived for steady state conditions. A number of these can be found in the literature and include the Borisov, Giger, and Joshi methods[1], Babu and Odeh[2], as well as others. Each steady state equation has the same basic form as the following Joshi solution.

$$q_h = \frac{(0.007078 K_h \Delta P) / (\mu_o B_o)}{ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + (h/L)\ ln\ [h/(2r_w)]}$$

$$\text{where } a = (L/2)\ [0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}]^{0.5}$$

The denominator of this equation contains two terms. The first represents horizontal flow along the length of the well. The second, characterized by some form of $(h/L)\ln(h/2r_w)$, represents vertical flow perpendicular to the wellbore. If the length of the horizontal is significantly larger than the reservoir thickness (L>>h), this term is negligible, qh increases, and flow can be optimized. Thus, the thinner the reservoir bed, the more effective the horizontal application (for NCLU, h = 30' and L = 400' to 500'). In such cases, steady state horizontal equations approach the solution for a fully penetrating, infinite conductivity, vertical fracture. Essentially, the objective of a horizontal well is to build an infinite conductivity fracture, along a controlled, predetermined path.

Each method was used to estimate production or injection potential for each well. Typical results are displayed in Figure 2. Due to spacing, economic considerations, and technical limitations of the short radius drilling technology, horizontal wells at NCLU were limited to a maximum lateral length of about 800'. Actual lengths achieved in the best part of the pay were in the range of 400' to 500'. Predicted injection rates at this length were approximately 400 b/d, or a threefold to fourfold increase in injectivity over the equivalent vertical well.

Preliminary Analysis: Location and Orientation

It has been reported that optimum results are achieved when horizontal injection and production wells are drilled parallel to one another at opposite ends of a pattern.[3] Such a configuration can lead to a perfectly enhanced line drive. As seen in Figure 3, NCLU has been drilled on a 20-acre chicken wire pattern but acts much like a line-drive. The intent was to enhance the line drive, where possible, with horizontal laterals.

The pilot project involves three test cases. The first two cases include horizontal injectors supporting a pattern of vertical producers. The third case includes a horizontal producer supported by vertical injectors. Figure 4 shows the three subject wells and the proposed orientation of each horizontal lateral.

All three test cases are found in an area with an oil cut of >60%, with the average well producing 15 bopd. From material balance calculations, it is estimated that the remaining oil saturation in the area is nearly 60% in a carbonate with a residual oil saturation to waterflood of 38%. Injectivity limitations have adversely affected the flooding characteristics in this part of the field.

Drilling: Equipment Requirements

A short radius drilling system was selected in order to reduce directional drilling costs and eliminate exposure to the Second Slaughter Marine thief zone. A conventional workover rig was used for horizontal drilling operations. Additional equipment included a modified power swivel, mud mixing equipment, mud pit with shaker, and primary and standby pumps capable of circulating at 3-4 bpm and 2000 psi. The drill string consisted of 2-7/8", 10.4 ppf, grade "E" American Open Hole drillpipe and 4-1/8" Drill Collars in the vertical section of the well. In the curve and lateral section of the well, 2-7/8", 8.7 ppf, P105, PH6 tubing was used. The curve and lateral sections were drilled with an articulated mud motor. A wireline steering tool with a wet connect system was used for guiding and surveying the well path.

Drilling: Wellbore Preparation

The NCLU #441AW was the first of the three horizontal wells drilled. Wellbore preparation consisted of drilling a replacement well for the plugged-and-abandoned NCLU #441W. The well was cased so that the kick-off point was below the casing shoe.

The NCLU #422 was the second well in the project. This wellbore is a producer that was originally drilled in 1984. Wellbore preparation consisted of pulling the production assembly, cutting out a 20' section of casing, and setting a cement sidetrack plug. Wellbore preparation was relatively trouble free.

The NCLU #222W was the last well drilled. This wellbore is an injector that was originally drilled in 1949. The well had a history of casing integrity problems. Wellbore preparation consisted of pulling the injection equipment, milling out a fiberglass liner, cutting out a 20' section of casing, and setting a cement sidetrack plug. Operations to prepare this wellbore were overspent due to problems setting a cement sidetrack plug. Water flows from the Second and Third Slaughter contaminated the first two cement plugs. The Second Slaughter was exposed to the wellbore through badly corroded casing.

Drilling: Drilling the Curve

The curve section of the three wells ranged from 56' to 70' of drilled section with a drilling radius of 48' to 51'. The planned drilling radius was 45'. Operations were hampered by slow drilling rates and cracked or broken articulations in the articulated motor assemblies. Improvements were made to the articulated mechanism over the course of the three wells to prevent cracking and breaking problems.

All three curves were stopped too soon due to problems projecting the final angle at the end of the curve. The distance from the bit to the survey sensor point was approximately 23'. This 23' "blind spot" necessitates using previous surveys to make a prediction of the position of the bit. Due to undetected changes in the performance of the curve building assemblies, the projected angle at the end of the curve was less than predicted.

On the first well (NCLU #441AW), there was a problem with the azimuth being 20° to 25° off the planned course. This problem was due to lack of experience in the area for predicting the reactive torque. There were no problems orienting the curves in the planned direction on the other two wells. Figure 5 shows the actual and planned well paths for the three wells.

Drilling: Drilling the Lateral Section

Due to having insufficient angle at the end of the curve, the beginning of the lateral section dipped down to a lower true vertical depth (TVD) than planned (Figure 6). This meant that the end of the curves and the first part of laterals were placed in a non-productive section of the Third Slaughter Marine. The lateral section on NCLU #422 was increased to 739' from the planned 500'. The extra 239' was drilled to make up for the section of the wellbore that dipped below the planned well path.

There were several problems that developed while drilling the lateral sections of the well. The two main problems were: 1) slow drilling due to motor performance or the inability to apply adequate weight to the bit and 2) drill string sticking problems. The problem with applying weight to the bit and the sticking problems are related since they are both a function of hole cleaning (cuttings buildup), wellbore tortuosity, bottom hole assembly configuration, and drilling fluid lubricity.

Drilling: Mud Logging

Each well was mudlogged from the kick-off drilling point to TD. The lithologic description of each sample, as well as information on penetration rate, hydrocarbon gas composition, hydrocarbon odor, oil staining, oil fluorescence, and cut fluorescence was collected during mudlogging.

Visible cut samples were then prepared for each sample interval. To prepare good visible cut samples, the cuttings must be well washed to remove the drilling mud. The cuttings were placed in the sun to air dry (not under a heat lamp where hydrocarbons could be driven off). Representative samples of cleaned, dried cuttings from each sampled interval were then placed into 8 ml glass vials about one-half full. The samples were compacted into the vials by tapping and chlorothene (a 1, 1, 1 - trichloroethane) was added to fill the vials. Chlorothene is a solvent which extracts oil from the rock. Labels with measured and true vertical depth were placed on the vials. If no oil was present in the rock, the solvent remained clear. Increasing concentrations of oil changed the color of the solvent in the following sequence: pale straw yellow, straw, dark straw, light amber, amber, brown, dark brown, to very dark brown. This was a quick, easy, qualitative method to visualize the volume of oil in each sample of cuttings.[4]

Initially, the plan was to collect 10' sample intervals from kick-off point to TD. It was quickly learned that a closer sample interval through the curve was very useful for picking both a "sweet spot" which had not been as well swept by the waterflood, as well as determining the top and base of the pay. These depths were picked from the visible cut samples. A 5' sample interval was used through the curve of the second well (NCLU #422). The third well (NCLU #222W) was sampled every 2' through the curve which allowed very accurate picking of the top and base of both the "sweet spot" and the pay. TVD varied by inches for every 10' drilled in the lateral section, so 10' sample intervals were collected.

There are a few precautions to take during preparation of visible cut samples. The visible cut color will depend on both the volume of cuttings as well as the volume of solvent used. Also, in areas with more than one oil composition, the gravity of the oil will affect the visible cut color. Therefore, this technique is very useful in single oil composition reservoirs if volume of cuttings and solvent are approximately constant for the entire sampled interval.

No logs were run prior to completion of the horizontal wells. Instead, the completion intervals were determined from the visible cut samples which were examined shortly after most of the oil had been extracted from the rocks. Sampled intervals with amber to dark brown visible cuts were completed. Some oil was present in intervals with lighter visible cuts (pale straw yellow to light amber), but this oil was extracted by the solvent over a period of days to weeks after preparation of the samples. This was interpreted as oil trapped in less permeable rocks and not likely to be moved by the waterflood.

Completion: Stimulation Options

The three horizontal wells were stimulated with hydrochloric acid (HCl) placed with coiled tubing. Since the pay interval is a dolomite which is highly soluble in HCl, the obvious choice of stimulation fluid was acid. The method of acid placement and diversion was less obvious.

The following placement techniques were considered: 1) HCl placed with multiple settings of an open hole packer in the lateral section; 2) HCl and diverting agent bullheaded into the lateral section below a casing packer set above the window and; 3) HCl placed with coiled tubing (with and without diverting agent). HCl placement with an open hole packer was considered risky as other operators in the Levelland Area had previously stuck open hole tools in lateral sections. The bullhead technique below a casing packer was the least risky technique considered; however, it was feared that only higher permeability sections of the lateral section would be effectively treated. Use of a diverting agent such as foam will improve the stimulation profile possible with the bullhead technique; however, it has been reported that the bullhead technique with foam diversion is less effective than with coiled tubing placement. Coiled tubing placement ensures acid/formation contact through the entire horizontal interval. Very successful stimulations utilizing coiled tubing placement without foam diversion have been documented in the literature.[5] For this reason, the NCLU horizontal wells were stimulated via coiled tubing and without foam diversion. It was theorized that the expense of foam diversion could be better spent on increased volumes of HCl.

Completion: General Stimulation Design

The three coiled tubing stimulations each had unique characteristics. However, some design parameters were consistent for all three jobs.

A side-blast dominant jet tool was attached to the end of the coiled tubing to maximize jetting energy on the formation face. The design of the jet tools was different for each well and was based on the expected downhole conditions of each stimulation. A minimal amount of down-blast through the tip was necessary to help remove debris in front of the jet tool.

The coiled tubing was guided with a 2-3/8" or 2-7/8" tubing string, packer, and tailpipe. The tubing and packer were necessary to protect the production casing from downhole treating pressures. Tailpipe through the curve section was necessary to minimize coiled tubing buckling stresses. Coiled tubing was run to the end of the lateral and withdrawn so that acid was evenly distributed throughout the lateral section.

The acid system consisted of 15% HCl with inhibitor, iron control, sulfur modifier, surfactant, penetrating agent, and friction reducer. Iron control concentration was highest in the leading portion of the acid and was tapered down throughout the job. The iron control was tapered because the majority of iron to be held in solution will be dissolved in the first portion of the acid. All other acid additive concentrations were held constant throughout the job.

Approximately 12 hours after each stimulation, the acid load was flowed and/or swabbed back to a test tank.

Completion: NCLU #441AW

The first well to be stimulated and completed was NCLU #441AW. This well was a new drill well with the kick-off point located below the casing shoe. The wellbore configuration is illustrated in Figure 7.

Prior to stimulation, NCLU #441AW was put on injection so that injectivity before and after stimulation could be compared. The injection equipment consists of 2-3/8", 2500 psig fiberglass injection tubing, an injection packer with an on/off tool, and 40' of 2-3/8" fiberglass tailpipe. With the exception of the tailpipe, this design is identical to that of a vertical injection well. The primary purpose of the tailpipe is to protect the anhydritic portion of the curve from erosion and dissolution. A secondary purpose of the tailpipe was to minimize coiled tubing buckling during the stimulation.

The horizontal lateral was stimulated with 32,000 gals 15% HCl via a 1-1/2" coiled tubing string. The coiled tubing was run through the injection string. This volume of acid equates to approximately 70 gals/ft of pay. Approximately 70' of the 532' lateral was not stimulated since this section was drilled slightly below the targeted pay. The coiled tubing was withdrawn very quickly through the 70' section so that acid would not be wasted.

The injection rate after drilling the lateral and prior to stimulation was 364 b/d at a surface pressure of 1470 psig. Initial injection after stimulation was 866 b/d at 1125 psig. Current stabilized injection rate is 550 b/d at 1950 psig. This represents an injectivity increase of more than 300% from that of the vertical completion.

Completion: NCLU #422

The only producing well of the program was NCLU #422. NCLU #422 was a re-entry in which a window was cut and a kick-off plug was spotted for drilling purposes. The wellbore configuration is illustrated in Figure 8.

The well was not produced prior to stimulation. It was stimulated with 20,000 gals 15% HCl via a 1-1/2" coiled tubing string. This volume of acid equates to approximately 40 gals/ft of pay. The coiled tubing was run through a 2-7/8" workstring, treating packer, and 2-7/8" tailpipe through the curve (to minimize coiled tubing buckling). Approximately 200' of the 739' lateral was not stimulated since this section was drilled slightly below the targeted pay.

Beam pump lift equipment installed in NCLU #422 is very similar to that of a vertical well. The end of the production tubing is just above the kick-off point; therefore, no production equipment is installed in the curve.

After drilling the lateral section and prior to stimulation, NCLU #422 swabbed 1 barrel of fluid per hour. After stimulation, the initial potential was 117 bopd and 70 bwpd. The current, stabilized production is 40 bopd and 14 bwpd. Production prior to drilling the horizontal lateral was 20 bopd and 10 bwpd; therefore, the horizontal increased oil production by approximately 100%.

Completion: NCLU #222W

NCLU #222W was a re-entry in which a fiberglass liner was milled out, a window was cut, and a kick-off plug was spotted for drilling purposes. Poor casing integrity across the Second Slaughter Marine thief zone made it probable that water would be injected out-of-zone unless remedial action was taken.

Two options were considered to minimize the possibility of out-of-zone injection: 1) a liner through the curve section and across the thief zone and 2) an open hole isolation packer set in the curve section. Installation of a liner was considered risky since the likelihood of a successful cement job through the curve was very low. It was decided to install an open hole packer in the curve.

Like #441AW, #222W was put on injection prior to stimulation. Injection equipment consisted of two injection packers. The top packer was set above the bad casing so that a successful pressure test could be obtained for regulatory purposes. The bottom open hole isolation packer was set in low permeability, anhydritic rock that separates the Second Slaughter Marine from the Third Slaughter Marine. It was hoped that the open hole packer would provide a strong enough seal to prevent injected water from channelling around the packer and into the thief zone above. Fiberglass tailpipe was run for the same reasons as in #441AW. Injection string detail is illustrated in Figure 9.

Prior to stimulating, an injection profile was run to determine if the open hole packer was preventing injection into the thief zone. The profile log indicated that the packer was holding; however, it appeared that injected water was migrating into the thief zone through the anhydritic barrier. This is possible since erosion/dissolution of the anhydritic barrier is common at NCLU.

Measures were taken to minimize the possibility of stimulating the thief zone. Prior to running coiled tubing in the hole, a high viscosity gel was bullheaded so that it covered the first 100' of the lateral section. The coiled tubing was then run through the gel to the end of the lateral section. The intent of the gel was to provide a barrier between the desired stimulation interval and the thief zone.

NCLU #222W was stimulated with 20,000 gals 15% HCl via a 1-1/4" coiled tubing string. The coiled tubing was run through the injection string. This volume of acid equates to approximately 50 gals/ft of pay. Approximately 400' of the 533' lateral section were stimulated to minimize the possibility of breaking down the gel and stimulating the thief. Unfortunately, the gel did not perform to specifications and it is unlikely that an effective barrier was achieved; however, stimulation pressure and rate data indicate that breakdown occurred before acid could have reached the thief zone.

Injection rate after drilling the lateral but prior to stimulation was 69 b/d at a surface pressure of 1500 psig. Initial injection after stimulation was 470 b/d at 1550 psig. Current stabilized injection rate is 580 b/d at 1850 psig. This represents an injectivity increase of over 300% from that of the vertical completion.

Conclusions

1) The objective of increasing injectivity and producibility with horizontal wells at NCLU was achieved. Injection rates increased over 300% while oil production rates increased approximately 100%.

2) It is too early to quantify incremental reserves realized from improved sweep efficiency with the horizontal wells.

3) The use of short radius drilling technology proved to be a successful application at NCLU. Poor casing integrity will compound wellbore preparation problems.

4) Mudlogging and visible cut sample analysis were instrumental in maximizing the footage of pay contacted by the horizontal laterals.

5) Stimulation of the lateral sections with HCl through coiled tubing without diversion was effective in increasing injectivity and producibility. Further work is necessary to optimize the stimulation technique.

Nomenclature

L	Horizontal well length (feet)
h	Reservoir thickness (feet)
r_w	Wellbore radius (feet)
r_{eh}	Drainage radius of horizontal well (feet)
μ_o	Oil viscosity (cp)
B_o	Formation volume factor (RB/STB)
ΔP	Pressure drop from drainage boundary to wellbore (psi)
k_h	Horizontal permeability (md)
a	Half the major axis of drainage ellipse (feet)
q_h	Horizontal well flowrate (b/d)

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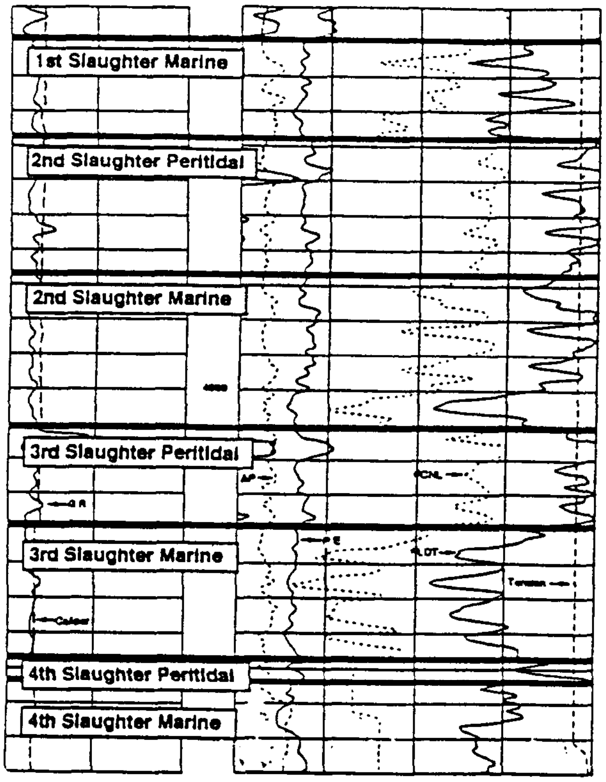

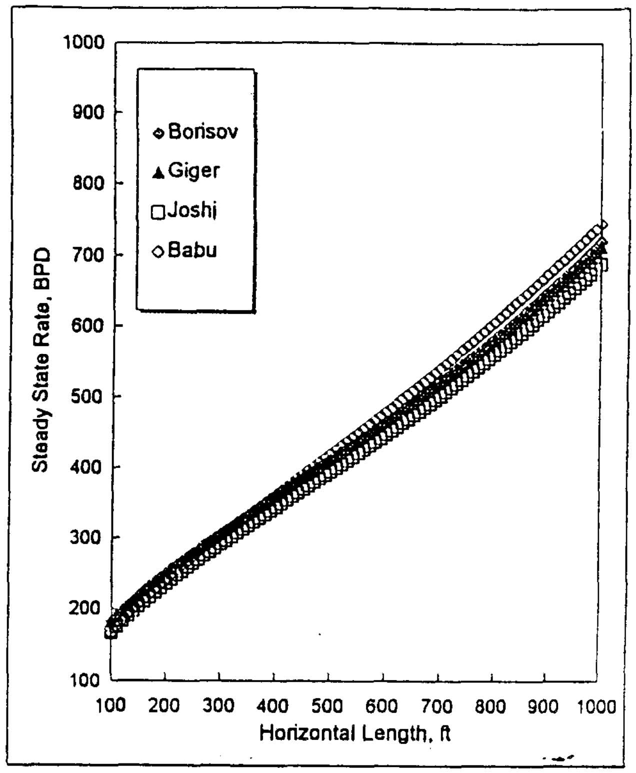

Figure 1 - Compensated Neutron-Lithodensity Type Log

Figure 2 - Steady-State Flow Predictions

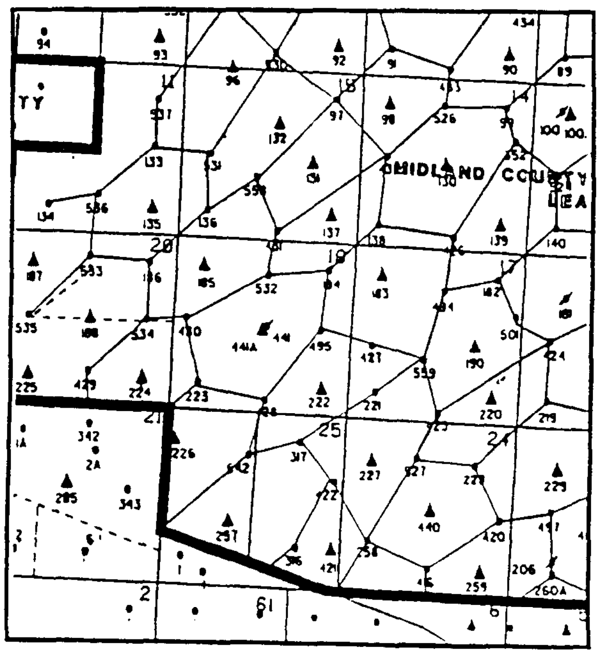

Figure 3 - NCLU Pattern Configuration

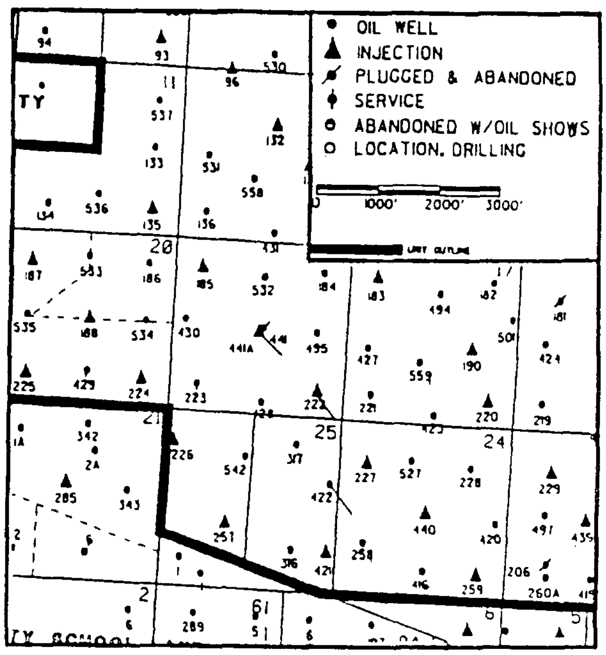

Figure 4 - NCLU Horizontal Well Locations

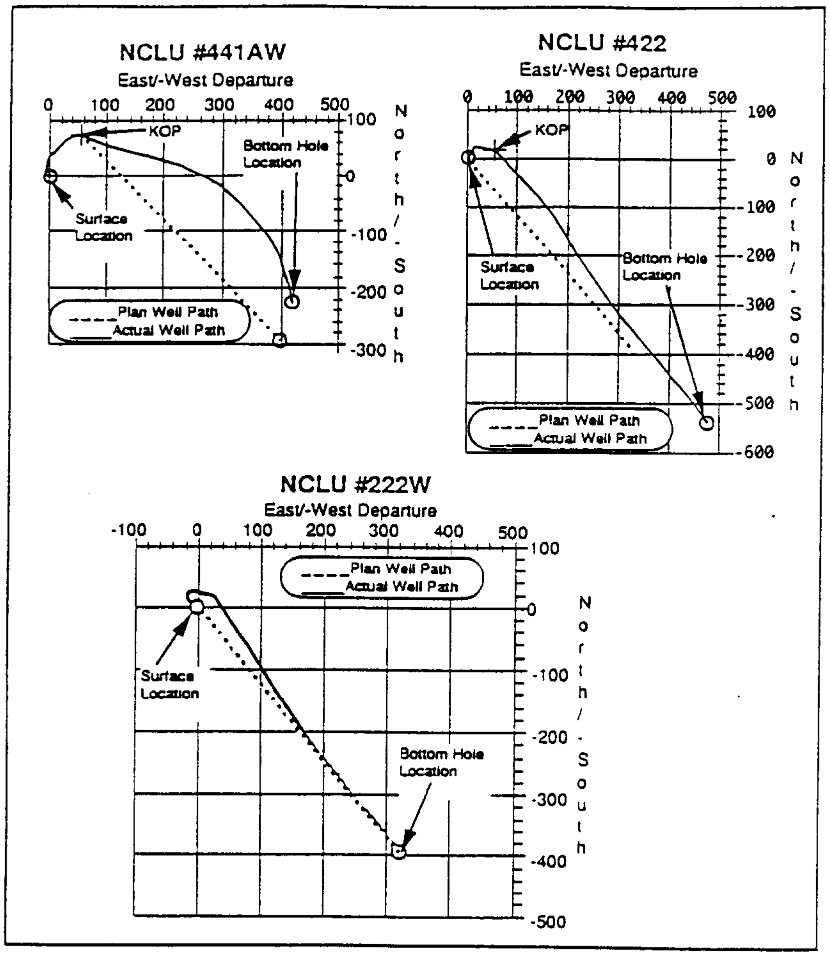

Figure 5 - Top Views of Planned vs. Actual Well Paths

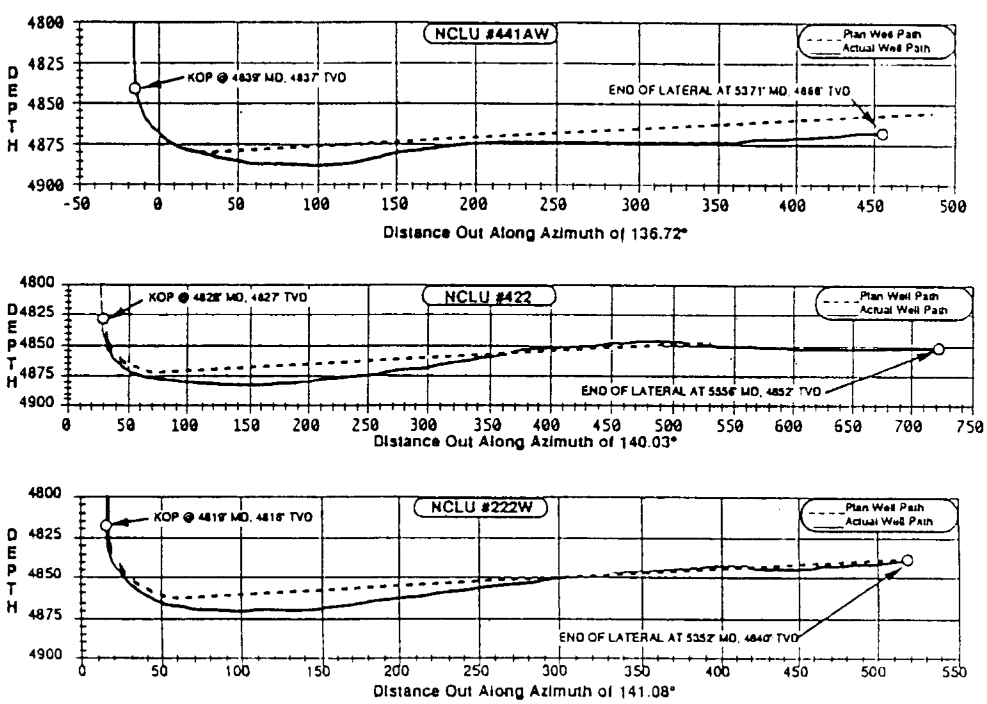

Figure 6 - Vertical Section Views of Planned vs. Actual Well Paths

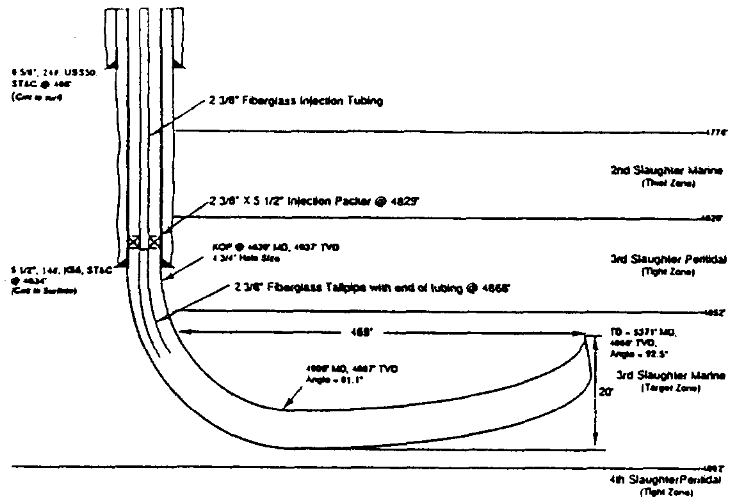

Figure 7 - NCLU #441 AW Wellbore Diagram

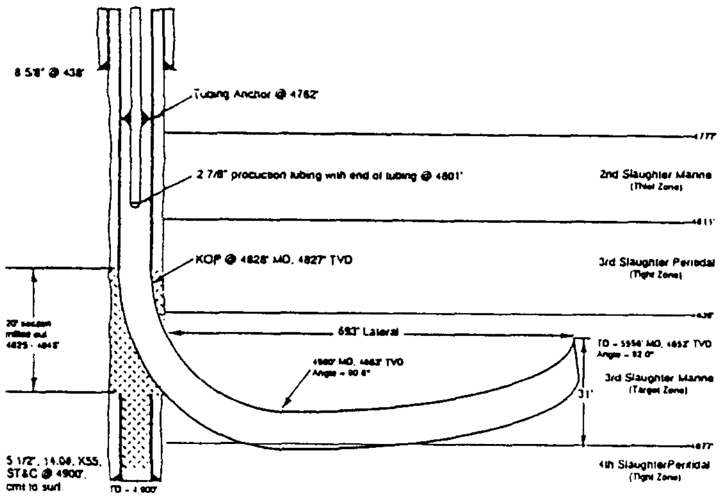

Figure 8 - NCLU #422 Wellbore Diagram

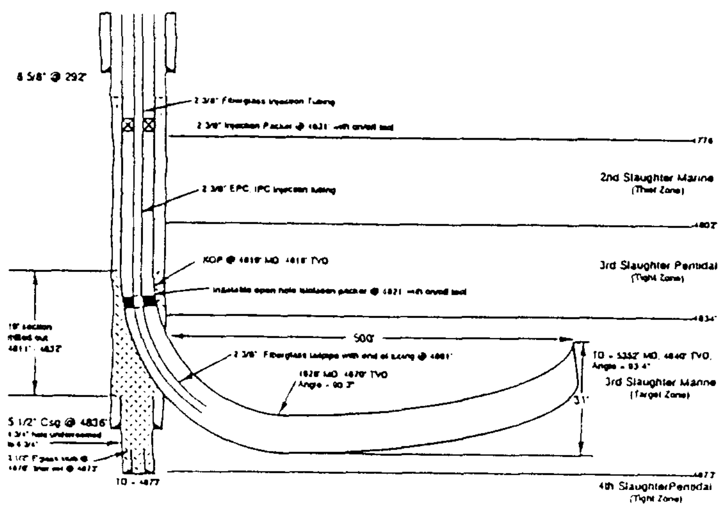

Figure 9 - NCLU #222 W Wellbore Diagram