# UNIQUE ENGINEERED COMPLETION USING HORIZONTAL CEMENTED LINERS IMPROVES STIMULATION IN WEST TEXAS LOW-PERMEABILITY CARBONATE RESERVOIRS

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## ABSTRACT

This paper presents two field case histories from multiyear horizontal completion projects in west Texas that were very successful at exposing the "false economy" of not cementing casing in horizontal wells drilled in low-permeability reservoirs. Moderate increases of 20 to 25% in initial well costs yielded a 3- to 10-fold increase in discounted cash flow through improved hydrocarbon recoveries. Case histories are developed for adjoining wells with similar reservoir characteristics and differing completion techniques. Comparisons of single lateral cemented liner completions to openhole completions and uncemented liner completions will also be presented.

## INTRODUCTION

For many recent as well as planned projects throughout the world, the increased production per completion dollar that horizontal completions can offer provides most of the economic justification for developing a new field or for additional drilling in an existing field. Drilling a horizontal lateral section increases the possibility of improving production rates per well, compared to vertical completions in the same reservoir.[1] However, operators understand that the added expense of such drilling requires a significant improvement in production rates, and they assume that the higher production rates will be automatic. Under this assumption, choosing the obvious cost-reduction benefits of openhole completions seem to be a wise economic decision, but operators often find that many of these wells severely underperform as openhole completions.[2-6]

Case Study 1 will compare cemented liner completions (CLC) to openhole liner completions (OHLC) in three distinctly different reservoir quality areas within the same field. Case Study 2 will compare a dual opposed OHLC method well to direct offset wells drilled later with the CLC method.

## FIELD AND RESERVOIR DESCRIPTION

The project area consists of a group of Permian Basin oil and gas fields located in southwestern Midland County, Texas (Fig. 1). Table 1 shows typical well and reservoir descriptions. The horizontal wells were completed in the Devonian (Thirty-one) formation with lateral sections ranging from 2,600 to 4,400 ft in length. Fig. 2 shows a wellbore schematic typical of completions discussed here. Depths to the top of the Devonian occur from 11,600 to 12,000 ft in the project area, with the top of the main pay zone existing 200 to 275 ft deeper. The lithology can be described as a dense cryptocrystalline limestone. Laboratory analyses of drill cuttings were performed to determine mineral composition and acid solubility. In nonpay intervals, the rock consists of up to 99% calcium carbonate. Acid solubility in these intervals is equally high. However, in pay intervals, silica or dolomite increase to combined percentages up to 50%, reducing acid solubilities to 50 to 75%.

## DRILLING AND COMPLETION CONSIDERATIONS

It was initially believed that increased fracture-stimulation effectiveness would result if the horizontal wellbore started perpendicular to the natural fracture orientation. However, later drilling did not indicate the presence of significant natural fracturing in the reservoir. Therefore, other factors became more important in selecting a desired orientation of the wellbore to achieve maximum stimulation effectiveness. The reservoir seemed to maintain the greatest continuity and lateral extent along depositional (stratigraphic) strike. A horizontal wellbore aligned parallel to depositional strike increases fracture-stimulation effectiveness by increasing the opportunity for the bit to remain within the targeted pay interval and contact more of the productive reservoir rock with the borehole.

Before the proper pay-interval depth can be selected for lateral placement, a vertical pilot hole must be drilled through the reservoir and evaluated with openhole petrophysical logs. **A** typical openhole-logging suite includes neutron-density, resistivity, and sonic logging, all with a gamma ray. Following petrophysical evaluation, the target interval is selected. A trajectory for the horizontal well path is further defined with dip and azimuth, determined by geologic data.

During drilling of the lateral, mud logging operations are used to obtain geologic information about the rock. Careful attention must be given to directional drilling activities, which must be integrated with mud logging operations and geologic data to keep the bit in the pay zone.

Proper selection of perforation locations also helps increase fracture-stimulation effectiveness. After the liner is cemented in place, a cased-hole petrophysical logging program is conducted to determine the optimum locations of perforations.

## CLC CEMENTING METHODS

The major purpose of a cementing program is to create effective zonal isolation for controlling fracture placement and effectiveness. Therefore, the cement job should adequately fill the liner-drilled hole annulus and must not be a detriment to effective communication to the formation when fracture stimulating or during production.
Although conventional cements are effective, in this application they can also negatively impact the completion because of their low solubility rates in acid. This low solubility rate can inhibit fracture initiation, cause excess tortuosity during both stimulation and production, and seal off a substantial portion of the drilled'hole. In short, conventional cements limit an operator's ability to improve reservoir communication beyond what is achieved with a jet-shot perforation.

**A** nonstandard acid-soluble cement (ASC) was used to cement the liners in these projects. This type of cement has a faster solubility rate in acid and effectively dissolves in acid-based stimulation fluids, creating an enlarged area of communication immediately adjacent to the perforated annulus area, while still maintaining excellent zonal isolation in the annulus. The properties of ASC provide the benefits of conventional cement and thick gel blocks without the associated problems inherent to both of these methods. Risk reduction and time savings are associated with eliminating the need to run retrievable tools into the horizontal liner to separately isolate and break down each set of clustered perforations. Stimulating low-permeability reservoirs with long horizontal sections in a single stage using limited-entry clustered perforating is most cost-effective when the perforation friction associated with each cluster can be accurately predicted.[5] Conventional high-compressive-strength Portland cement, which typically has less than 5% acid solubility, cannot be reliably removed and leave all perforations openly communicating with the formation without isolating individual perforations using retrievable service tools and balling out each perforation cluster individually with perf-pack ball sealers, increasing costs and risk.

## PERFORATING METHODS AND INTERVAL SELECTIONS

After reviewing the mud log and porosity log, intervals were selected for perforating and fracture acidizing. To help ensure perforation quality, single-trip, multiple-zone, tubing-conveyed perforating (TCP) was used. An average of 12 zones was shot simultaneously on a single TCP trip into a typical (approximately 3,600-ft) lateral section of the well.

The Point Source Cluster Perforating (PSCP) method is designed to achieve pressure-driven (limited-entry) fluid distribution during stimulation, which distributes the treatment fluids evenly between all zones. A typical perforation design has 55 to 65 perforations for a 110- to 120-bbl/min designed fracturing rate. The typical perforation design for 140 to 180 bbl/min total injection rates contained 75 to 90 perforations in 12 to 14 clusters. Table 2 describes a typical perforating design.

## STIMULATION FLUIDS AND METHODS

**A** horizontal well reservoir simulator was calibrated to the project's specific well conditions to develop a methodology for selecting the number of fractures that should be placed. In this field, multiple cases for a single 3,000-ft horizontal lateral draining a rectangular reservoir (320 acres) were calculated with input data representative of well parameters in the study area. Other studies indicated that effective propped fracture half-lengths of 100 ft could usually be achieved. Spacing the fractures evenly along the lateral, multiple simulations were made with 2, 4, 6, 8, and 10 transverse fractures, each with a 100-ft half-length (infinite conductivity). In Fig. 3, these results are plotted in a format that clearly depicts the producing rate and 10-year ultimate recovery values for each of these completion conditions, using an x-axis of initial (first month average) production rate and y-axis of ultimate hydrocarbon recovery.

With fracture acidizing of carbonates, the fluid volumes and rates are responsible for fracture-geometry creation, but live acid must be able to reach deep into these fractures before fracture conductivity is created more than just a few feet from the wellbore. Extensive laboratory work was undertaken to help determine the required properties of the acid fluids used, and computer fracture simulations helped determine the best method for pumping the fracture-stimulation treatments. The acid system chosen was an in-situ crosslinking gelled acid (ICA) system that provided a controlled stimulation of the fracture face by dynamically diverting live acid away from previously stimulated areas to new areas of the fracture. Fig. 4 shows how ICA acid is a low-viscosity linear gelled acid until reaction with the formation causes the pH of the system to rise and crosslinking to initiate at pH values of approximately 2.5.

The low-viscosity linear behavior of ICA in the tubulars provides excellent friction reduction, resulting in lower HHP requirements and higher overall treatment rates. The delayed crosslinking behavior of ICA allows the system to react with the formation face along the fracture wall, creating wormholes. Once the ICA in the wormhole spends, the pH of the system rises, and crosslinking in the wormhole causes a rapid rise in viscosity that diverts unspent acid to new areas of the fracture system, thus maintaining more live acid in the main fracture and yielding deeper penetration than could be achieved with linear gelled acid systems. As the pH of the ICA system rises from further reaction with the formation, the crosslinked ICA reverts to a low-viscosity linear gelled acid system that can be easily recovered.

## Case Study 1: Wellbore Orientation Transverse vs. Longitudinal Fractures

Most situations encountered with the stimulation of horizontal wells in low-permeability reservoirs provide better production results when the hydraulic fractures are generally transverse to the wellbore. The more aligned the fracture direction is with the borehole axis, the less benefit that can be obtained from fracture stimulation treatments. An exception to this rule occurs when the producing pay zone is very thick, and fracture height growth may be as beneficial as fracture length. In the Parks 2 field, where pay-zone thickness is not large, a clear comparison of this effect occurred when spacing limitations required Well B, completed adjacent to Well A (a CLC project well), to be drilled 90" opposed to the CLC well. At the time Well B was drilled, the operator understood the advantages of the CLC method, and this completion methodology was strictly followed, with the exception of a variable wellbore trajectory.

Fig. 5 is a post-stimulation tracer log from Well A. In this well, the lateral section was drilled transverse to the preferred fracture plane (PFP). The tracers show red only at very isolated intervals along the borehole, indicating successful concentrated stimulations only at the small perforated intervals. This situation seemed to result in long conductive fractures and excellent initial and sustained production responses.

Fig. 6 is the tracer survey for Well B. This well was in an adjacent section from Well A. Well B was completed as a CLC project well in nearly all respects, except that it was drilled with the lateral generally in the direction of the PFP. The post-stimulation tracer log indicated excellent fracture coverage along the lateral. Although production was significantly below the "transverse fractures" of Well A (Fig. 5), Well B still produced above the average for offset wells completed with the OHLC method.

## Offset Operators' OHLC Stimulation Methods, Infield Area

Horizontal wellbores in the offset operators' initial completions in the main field area typically were oriented east to west. This orientation resulted in hydraulic fractures forming longitudinally along the lateral section. The wells were completed openhole using a common manifold arrangement for stimulation. This configuration requires the setup of two isolated, independently focused frac spreads. Each set of pumping equipment requires independent blending and pumping standby capabilities, making the operation more challenging than conventional single-wellbore path treatments. The desired high injection rates down the annulus required additional special wellhead flange adapters. The treatments were pumped at maximum rate and pressure through both the tubing and the annulus. The only limitation to maximum rate was the rate capacity of the equipment or the pressure limits of the wellhead equipment and tubulars.

These acid fracs employed nongelled 28% HCl acid with friction reducer alternated with stages of titanate-crosslinked fracturing fluids. Equal volumes of acid and crosslinked gel were pumped with the gross acid volume calculated on 60 gal/ft of horizontal section. A typical treatment schedule for this type of treatment is presented in Table 3. Tubing was run to the end of the lateral, and fluids were pumped down both the tubing string and the annulus simultaneously. Injection rates down the annulus averaged 60 to 80 bbl/min with wellhead treating pressures (WHTP) of 3,500 to 4,500 psi. Average injection rates down the tubing string were 15 to 20 bblimin at 7,000 to 8,000 psi.

Post-treatment pumpdown temperatureitracer logs were run on many of the wells. The logs indicated that stimulation was achieved in the heel and toe areas of the wells with little or no indication of stimulation in the middle section of the laterals. A much higher degree of stimulation was achieved in the heel area where injection rates were highest. Satisfacopportunity for the bit to remain within the targeted pay interval and contact more of the productive reservoir rock with the borehole.

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### Case Study 1: – Wellbore Orientation Transverse vs. Longitudinal Fractures

Most situations that will be encountered with the stimulation of horizontal wells in low-permeability reservoirs will provide better production results when the hydraulic fractures are generally transverse to the wellbore. The more aligned the fracture direction is with the borehole axis, the less benefit that can be obtained from fracture stimulation treatments. An exception to this rule isoccurs if when the producing pay zone is very thick, and fracture height growth may be as beneficial as fracture length. In the Parks 2 field, where pay-zone thickness is not large, a clear comparison of this effect occurred when spacing limitations required Well B, completed adjacent to Well A (a CLC project well), to be drilled 90° opposed to the CLC well. At the time Well B was drilled, the operator understood the advantages of the CLC method, and this completion methodology was strictly followed, with the exception of a variable wellbore trajectory.

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challenging than conventional single-wellbore path treatments. The desired high injection rates down the annulus required additional special wellhead flange adapters. The treatments were pumped at maximum rate and pressure through both the tubing and the annulus. The only limitation to maximum rate was the rate capacity of the equipment or the pressure limits of the wellhead equipment and tubulars.

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OFFSET OPERATORS' OHLC STIMULATION METHODS. FLANK AND EDGE AREAS

Before this study, offset operators attempted to either improve stimulation or reduce stimulation costs in flank and edge well areas. Attempts to increase acid coverage in the laterals included using an uncemented liner string with limited-entry predrilled ported sections. The preperforated tubing string was then pulled from the lateral, and the wells were produced as openhole completions. Acid coverage was somewhat improved by this method.7 Further cost reduction or optimization attempts involved lowering the HCl acid concentration to 15% and varying the acid volumes pumped between 35 and 65 gal/ft of lateral. Other efforts to improve production rates included using branched, openhole, multiple laterals and changing lateral orientation to north/south to achieve transverse hydraulic-fracture orientations.

### Case Study 2: Offset Operators OHLC Stimulation Methods

This well was drilled as a dual opposed lateral. The primary purpose of this method was to reduce the wellbore drawdown from the toe to the vertical wellbore, with each lateral about one-half the horizontal extent of the field-common, single-lateral length of approximately 3,500 ft. This well was stimulated in two stages employing a removable preperforated uncemented liner to help distribute acid over the entire length of the lateral. This preperforated liner method (previously discussed) has commonly been referred to as the "sprinkler system" or "sprinkler frac" method. Stimulation fluids consisted of multiple stages of 20% gelled HCl acid alternated with crosslinked gel fracturing fluids. Treatment rates were between 60 and 80 bbl/min pumped down the casing and liner. The liner was pulled and run into the opposing lateral and the process was repeated. Table 4 presents the treatment schedule used to treat each of the laterals.

CLC STIMULATION METHOD

The chosen stimulation fluid for the CLC wells in Case Study 2 was an ICA system using 17 to 20% HCl acid-based fluid that allowed adequate but controlled etching of the fracture walls. The ICA system pumps as a thin-gelled fluid (1.5 to 2% v/v polymer loading) that leaks off into the formation matrix along the fracture walls. As the ICA leaks off, it slowly spends and creates wormholes in the fracture walls of the formation. When the ICA has spent to the point that the pH is in the range of 2.5 to 3.5, the ICA fluid viscosifies rapidly and further leakoff into the wormhole is essentially stopped so that live acid is preserved for reaction further down the fracture. Thus, a controlled stimulation of the fracture face takes place for extended distances away from the wellbore.

The hollow core castings in Fig. 6 provide a visual comparison of wormholing results during the same time period and reaction temperature for a conventional gelled-acid system and the ICA system. The conventional gelled-acid system without the ICA crosslinking additives continues to leak off down the wormholes in the simulated fracture face and never inhibits fluid loss. While the net result for the conventional gelled-acid system is better etching of the frac length than would result from a nongelled-acid system, it is less than that obtained by the ICA system,

In the CLC wells, the area selected for possible location of perforated intervals for stimulation points along the lateral was "high graded" based on pumpdown, cased-hole log response, mud-log drilled-cuttings sampling, mud-log gas shows, and rate-of-penetration information. The maximum number of perforated intervals was limited to an average of one per 250 to 300 ft of lateral length to assure that every zone would be stimulated.

All of the CLC stimulation treatments discussed in this paper were pumped down large-diameter (7-in. OD or greater) casing with a 4 X-in. liner set above the curve and through the horizontal section and cemented with ASC. The Case Study 1 treatments were pumped at the maximum obtainable rate for each well (up to 130 bbl/min) within WHTP and equipment-rate capacity limitations. A dual-spread setup of fracturing equipment was required for these treatments. The typical average overall rate was 110 to 120 bbl/min. To protect the wellhead equipment, a full-opening frac valve and casing wellhead isolation tool was used.

For Case Study 1, the gross acid volume per foot of lateral length was typically based on 45 to 50 gal/ft. Table 5 shows a typical design for the Case Study 1 CLC stimulation treatment. The initial acid stage was a nongelled 20% HCl acid with friction reducer and iron-control additives. This stage was used to further break down and clean the perforated intervals, establish fracturing rates, and "pickle" the tubulars. This stage was followed by a single stage of crosslinked gel to obtain good fracture extension before the acid arrival. A large amount of ICA was then pumped, followed by nongelled HCl acid that was subsequently overflushed prior to the wellbore flush stage.

Case Study 2 wells were stimulated with 125 galift. Table 6 shows an example of a typical treatment schedule for Case Study 2 CLC completions. These wells were treated down 7-in. casing into 4 %-in. cemented liners at rates from 160 to 190 bblimin. The higher rates were considered necessary because of the greater vertical extent of the pay intervals and higher permeabilityiporosity character of the Case Study 2 reservoir.

### Case Study 1: Economic Analyses, Old vs. New Approach

As discussed, reservoir quality is an accepted reference factor for determining well potential, even though it has almost no effect on drilling and completion economics (except to reduce required stimulation costs in a few high-producing wells). For this reason, the comparisons presented are separated into three categories: edge wells, flank wells, and infield wells. For each of these categories, conventional OHLC wells and wells using the new CLC method are compared. The economic analyses presented are intended to be accurate, yet somewhat generic, and not representative of any one operating company. The data included are valid for the timeframe in which most of these wells were drilled and completed. Because both gas and condensates were produced, the production data and economic comparisons presented are based on barrels of oil equivalent (BOE) rather than natural gas units.

Fig. 8 shows the field positions of the edge wells included in the production comparisons of Fig. 9. The net economic gain of the new CLC method is approximately $400,000/well over a five-year period, as seen in the economic comparisons of Fig. 10 that include predicted cash-flow data for edge wells. This gain is in spite of higher initial completion costs.

Fig. 11 shows the field positions of the flank wells that are included in the production comparisons of Fig. 12. For this group, the five-year average gain was $1,200,000/well (Fig. 13), a more dramatic example of the impact of more effective stimulation than for that of the poor-quality edge wells.

Infield wells for both the OHLC method and the CLC method are shown in Fig. 14. The greatest improvement in production was achieved in these wells, which had the best reservoir quality/potential. While infield wells completed with the conventional OHLC method were generally the best producers with this method, they nevertheless proved to be the most underperforming wells and the most in need of a completion that would provide effective stimulation. Production comparisons in Fig. 15 illustrate the enormous increased production rates achieved, and the economic comparisons of Fig. 16 show that predicted five-year cash-flow improvements for the CLC wells were a staggering $8,000,000/well. In this field, the better the reservoir quality, the more important the need to maximize the effectiveness of the stimulation treatment.

### Case Study 2: Economic Analysis, Dual Opposed OHLC vs. CLC

Fig. 17 shows the relative positions in the field for the OHLC and CLC wells. All of the wells were drilled within a 1 ½-year period with the dual opposed OHLC projects drilled first. Fig. 18 shows the individual well performance on a BOE basis, normalized to a common start date. Fig. 19 indicates that on average the CLC method produced 79,526 BOE/well more than the OHLC method for the first producing year of the well. On a $20/BOE basis, the CLC method averaged an extra $1,590,025 gross revenue per well for the first 12 months of production.

Additionally, Figs. 17 and 18 show that the best producers were the two CLC wells closest to a north/south alignment. It is believed that this wellbore orientation provides hydraulic fractures that are the most perfectly perpendicular to the lateral.

## PROJECT OUTCOME

When comparing wells completed using the conventional OHLC method to wells completed with the CLC method, an operator would expect to put the well into production with lower initial costs. However, the OHLC method severely limits the opportunity to effectively stimulate the reservoir. In the best reservoir-quality wells (infield), the OHLC method proved to be the most detrimental to enhanced production.

With a slightly higher initial investment and careful engineering practices, CLC method provided effective stimulation coverage of the lateral section. This coverage resulted in higher initial production rates and more effective drainage. In reality, many OHLC wells have encountered significant post-completion costs from attempts to iniprove production. These additional costs were not included in the "average" well completion costs for the comparisons in this paper. Later, offset laterals were added to some of the OHLC wells in attempts to achieve better production rates.

## CONCLUSIONS

When completing horizontal wells in low-permeability reservoirs, effective stimulation should be a primary completion goal in the decision-making process. Truly effective stimulation requires more engineering control during the drilling and completion process.

The CLC method has slightly higher initial costs than OHLC, but it can greatly improve ROI because it can provide the following benefits:

- Allow more effective stimulation coverage of the lateral
- Provide significantly higher producing rates initially and for an extended time
- Enhance early cash flow, which further improves economics beyond just total increased hydrocarbon recoveries


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## NOMENCLATURE

ASC = Acid soluble cement
BHST= Bottomhole static temperature
BOE = Barrels oil equivalent
CLC method = Cemented-liner method of completion
ICA = In-situ, crosslinked acid
IPR = Initial production rates
OHLC method = Openhole-liner method of completion
PFP = Preferred fracture plane
PSCP = Point source cluster perforating
ROI = Return on investment
TCP = Tubing-conveyed perforating
TVD = True vertical depth
WHTP = Wellhead treating pressure

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12. Vinson, E.F., Totten, P. L., and Middaugh, R. L.: "Acid Removable Cement System Helps Lost Circulation in Productive Zones," paper IADC/SPE 23929 presented at the 1992 IADC/SPE Drilling Conference, New Orleans, LA, 18-21 February.
13. Soliman, M.Y., Rose, R.E., and El Rabaa, A.W.M.: "Planning Hydraulically Fractured Horizontal Completions," World Oil (September 1989) 54-58.
14. Magee, J., Buijse, M.A., and Pongratz, R.: "Method for Effective Fluid Diversion when Performing a Matrix Acid Stimulation in Carbonate Formations," paper SPE 37736 presented at the 1997 Middle East Oil Show, Bahrain, 15-18 March.
15. Willett, R.M., Borgen, K.L., McDaniel, B.W., and Michie, E.: "Effective Well Planning and Stimulation Im proves Economics of Horizontal Wells in a Low-Permeability West Texas Carbonate," paper SPE 77932 presented at the 2002 SPE Asia Pacific Oil and Gas Conference and Exhibition, Melbourne, Australia, 8-10 October.

Table 1
Typical Well and Formation Properties

| | |
|---|---|
| **Vertical Section** | 7-in., 29-lb casing<br>to approx. 11,000 to 11,700 ft TVD |
| **Horizontal Section** | 6.125-in. hole;<br>4.5-in., 11.6-lb liner for 2,800 to 3,600 ft |
| **Formation** | Devonian (Thirty-one) |
| **Formation Top TVD** | 11,600 to 11,800 ft |
| **Average Gross Interval** | 200 to 300 ft |
| **Average Net Pay Interval** | Case Study 1 wells: 30 to 60 ft<br>Case Study 2 wells: 60 to 80 ft |
| **Average Pay Porosity** | Case Study 1 wells: Edge: 3 to 5%; Flank: 5 to 8%; Infield: 5 to 12%<br>Case Study 2 wells: 5 to 12% |
| **Average Pay Permeability (Rock Matrix)** | Case Study 1 wells: Mge: 0.01 to 0.03 md; Flank: 0.025 to 0.05 md; Infield: 0.05 to 0.2 md<br>Case Study 2 wells: 0.05 to 0.2 md |
| **Pay Zone Mineralogy** | 70 to 95% limestone; 2 to 15% dolomite;<br>0 to 20% chert: Trace to 0.5% clav minerals |

Table 2
Example Data from Part of Spreadsheet for Perforating Design and Expected Fluid Injection at Each Perforated Interval

| Distance from Heel (ft) | Wellbore Rate at Point (bbl/min) | Injection Rate at Interval (bbl/min) | Pipe Friction to Toe (psi) | Number of Perforations | Perforation Phasing | Shots per ft in Gun |
|---|---|---|---|---|---|---|
| 0 | 107 | 7.8 | 708 | 3 | 120 | 3 |
| 260 | 99 | 7.3 | 590 | 3 | 120 | 3 |
| 518 | 92 | 9.1 | 499 | 4 | 120 | 3 |
| 851 | 83 | 8.4 | 386 | 4 | 120 | 3 |
| 1,130 | 74 | 7.8 | 304 | 4 | 120 | 3 |
| 1,412 | 67 | 9 | 231 | | 60 | 6 |
| 1,760 | [illegible] | [illegible] | 156 | 5 | 60 | 6 |
| 2,074 | 49 | 7.5 | 100 | 5 | 60 | 6 |
| 2,274 | 42 | 8.5 | 71 | 6 | 60 | 6 |
| 2,474 | 33 | 8.2 | 49 | 6 | 60 | 6 |
| 2,821 | 25 | 7.8 | 22 | 6 | 60 | 6 |
| 3,195 | 17 | 8.7 | 4 | 7 | 60 | 6 |
| 3,384 | | | | | 60 | 6 |

'Design Ran psi per perforation,
assuming 0.4-in. perforation diameter.

| Stage | Volume (gal) | Cumulative Acid (gal) |
|---|---|---|
| 28% acid | 54,000 | 54,000 |
| XL Frac fluid | 54,000 | — |
| 28% acid | 54,000 | 108.000 |
| XL Frac fluid | 54,000 | — |
| 28% acid | 54,000 | 162,000 |
| XL Frac fluid | 54,000 | — |
| 28% acid | 54,000 | 216,000 |
| Overflush | 20,000 | — |
| Flush | 20,000 | — |

| Stage | Volume (gal) | Cumulative Acid (gal) |
|---|---|---|
| 20% Gelled HCl | 20,000 | 20,000 |
| Frac fluid | 20,000 | — |
| 20% Gelled HCl | 20,000 | 40,000 |
| Frac fluid | 20,000 | — |
| 20% Gelled HCl | 20,000 | 60,000 |
| Frac fluid | 20,000 | — |
| 20% Gelled HCl | 20,000 | 80,000 |
| Flush | 40,000 | — |

Table 5
Example of Typical Treatment on CLC Method Well with a 3,600-ft ASC Cemented Liner

| Stage | Volume (gal) | Cumulative Acid (gal) |
|---|---|---|
| 20% Acid | 29,000 | 29,000 |
| XL Frac fluid | 58,000 | — |
| 20% ICA acid | 115,000 | 144,000 |
| 20% Acid | 29,000 | 173,000 |
| Overflush | 40,000 | — |
| Flush | 20,000 | — |

Table 6
Example of Typical Treatment on CLC Method Well wiha 3,600-ft ASC Cemented Liner

| Stage | Volume (gal) | Cumulative Acid (gal) |
|---|---|---|
| 20% Acid | 30,000 | 30,000 |
| XL frac fluid | 80,000 | — |
| 20% ICA acid | 160,000 | 190,000 |
| 20% Acid | 50,000 | 210,000 |
| Overflush | 30.000 | — |
| Flush | 20,000 | — |

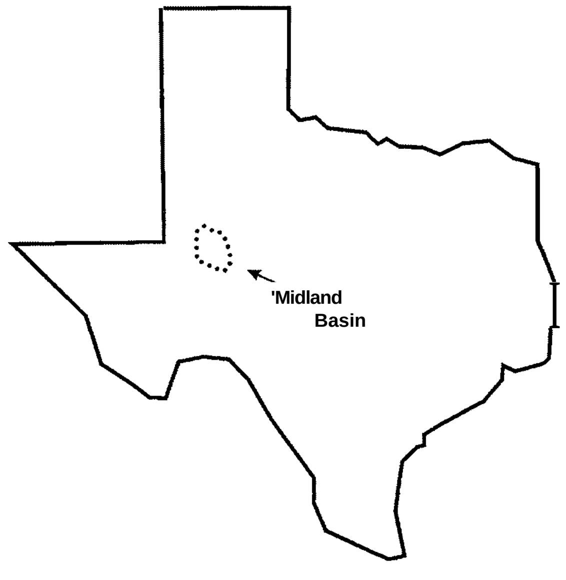


Figure 1 -Approximate Location of Field Within West Texas

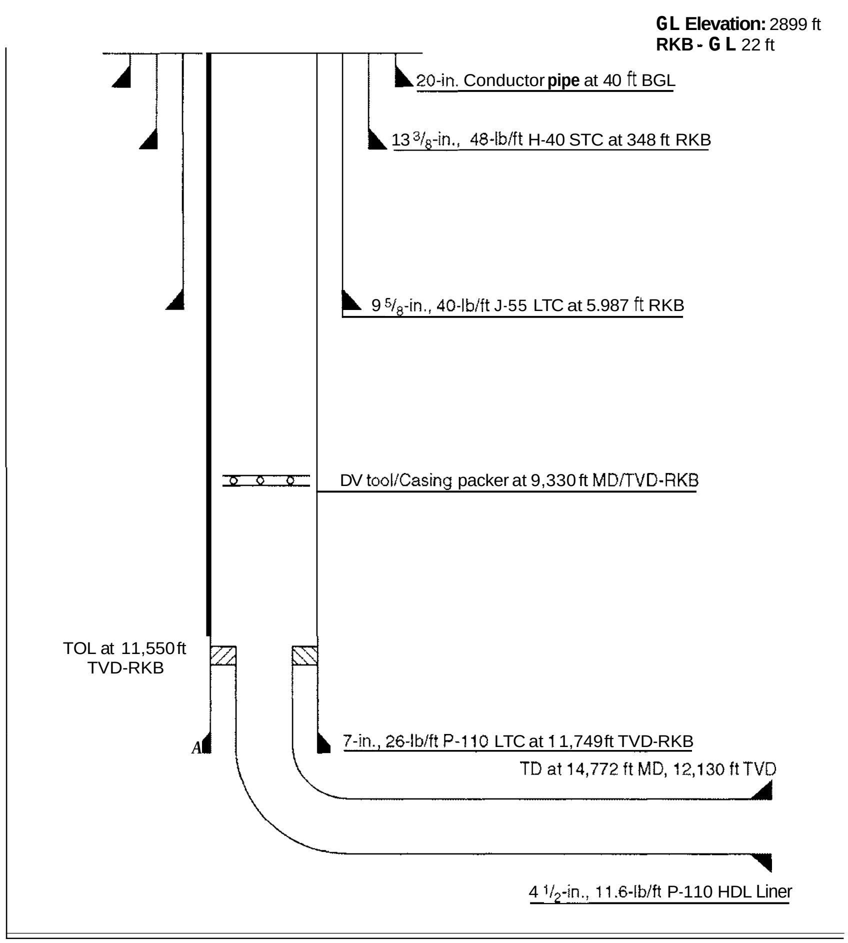


Figure 2 - Wellbore Schematic of Typical Completions in this Project

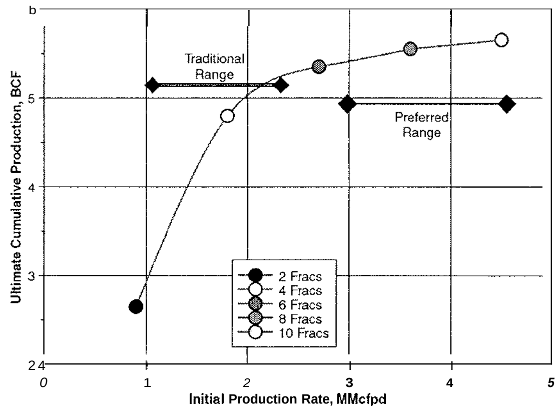


Figure 3 - Multiple Fracs in Horizontal Wells (limited entry perforating)

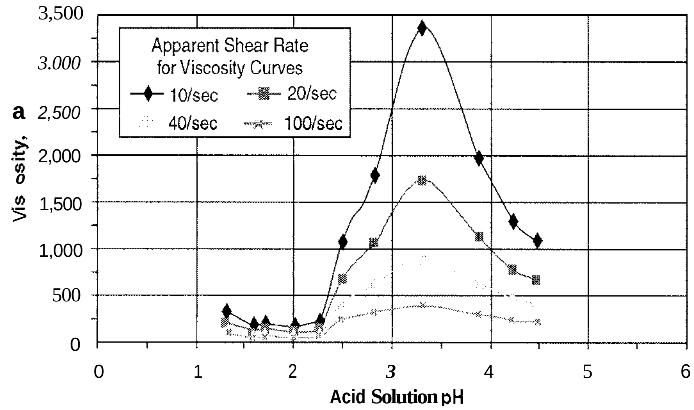


Figure 4 - Effect of viscosity increases on ICA as acid reacts and pH increases
Later, viscosity decreases for easy flowback

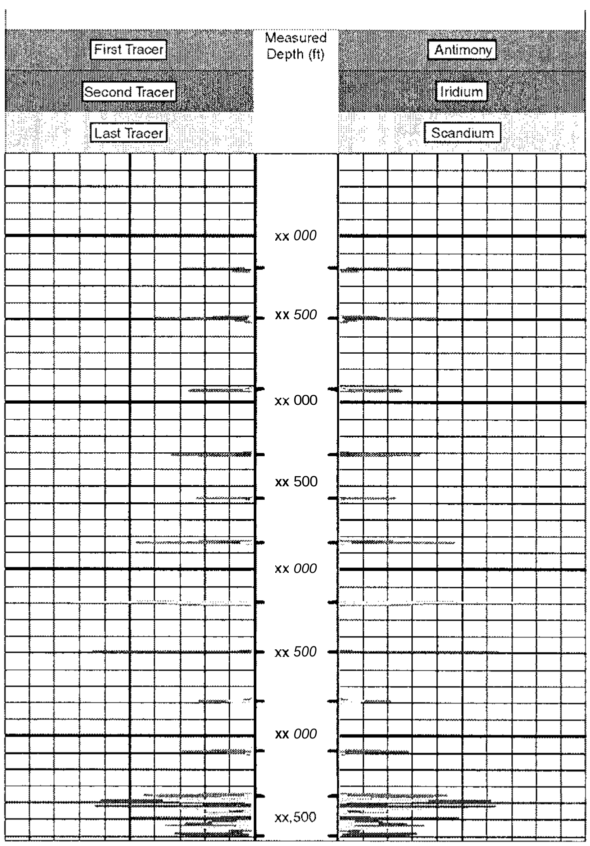


Figure 5 - Post-stimulation Tracer Log Typical of a CLC Well with the Lateral Section Drilled Transverse to the PFP, Resulting in an Excellent Production Response

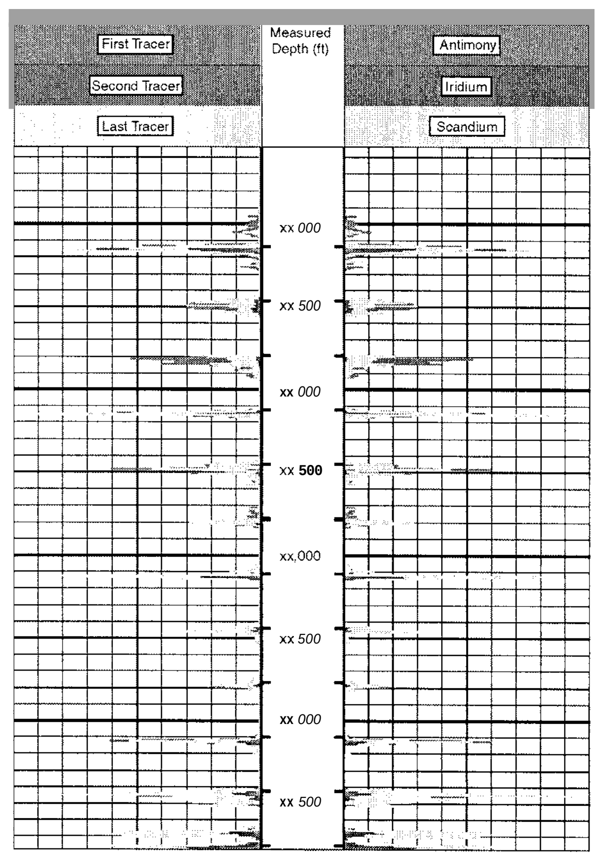


Figure 6 - Post-stimulation Tracer for Well B, Completed as a CLC Well, with the Lateral Section Drilled in Parallel to the PFP. Tracers show better control thtan with noncemented completions. The production response was not quite as good as with Well A.

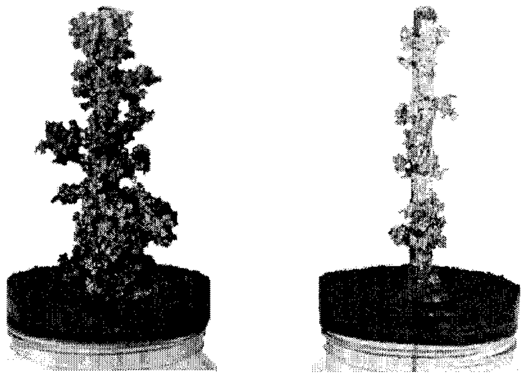


Figure 7 - ICA benefits wormole control even more than gelling HCl acid (reaction time and other test conditions identical).

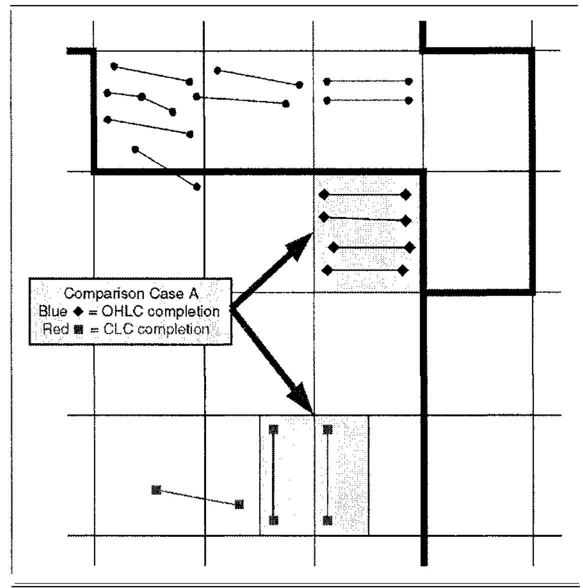


Figure 8 - Completion Comparison for Edge Wells

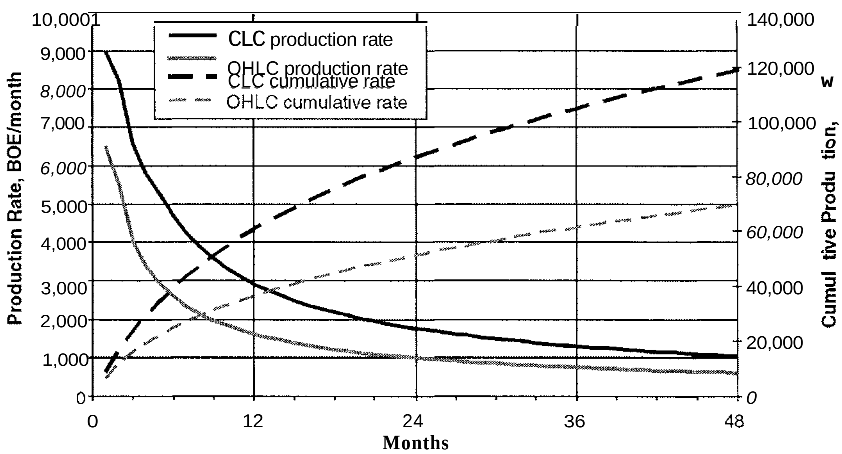


Figure 9 - Production Results Comparsin for Edge Wells

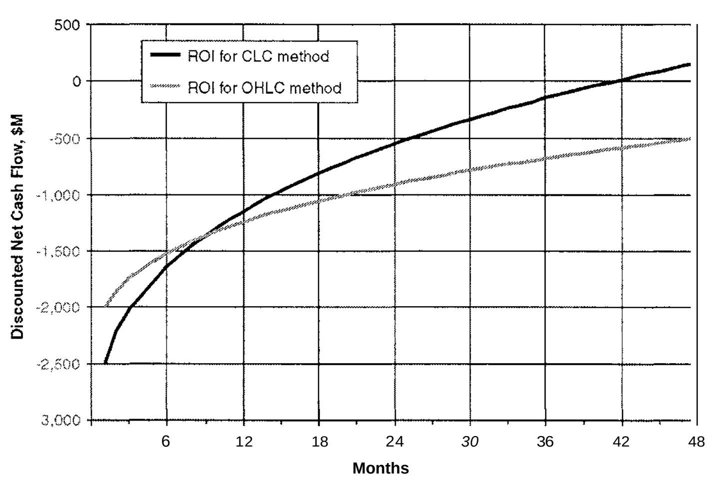


Figure 10 - Predicted Cash-flow Comparison for Edge Wells

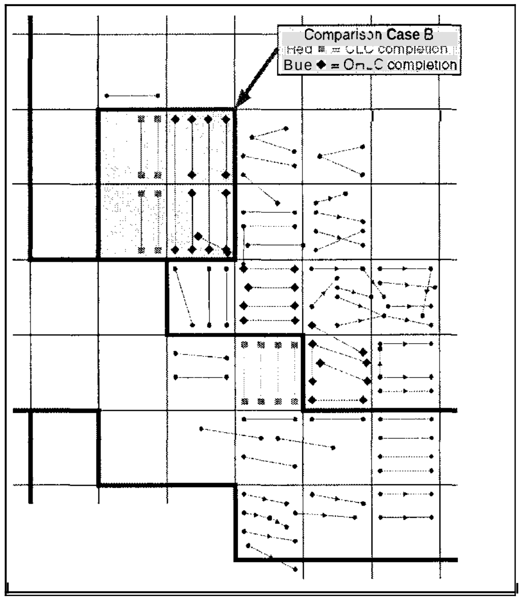


Figure 11 - Completion Comparison for Flank Wells

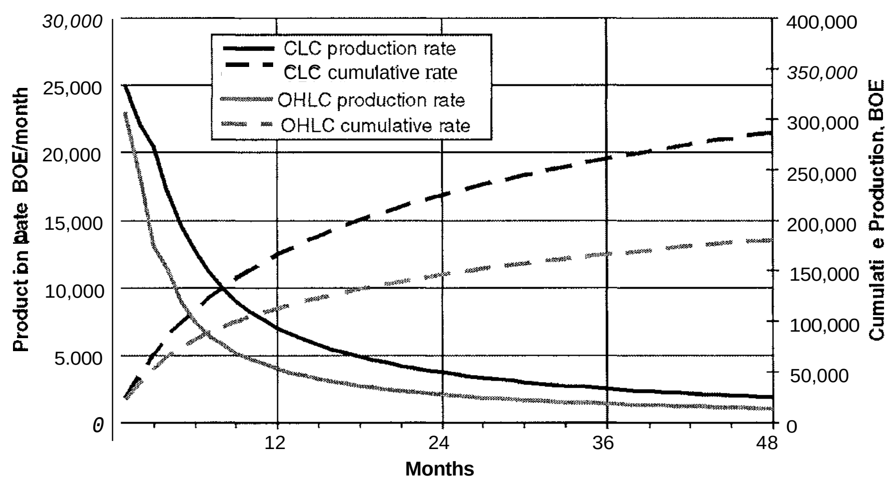


Figure 12 - Production Results Comparison for Flank Wells

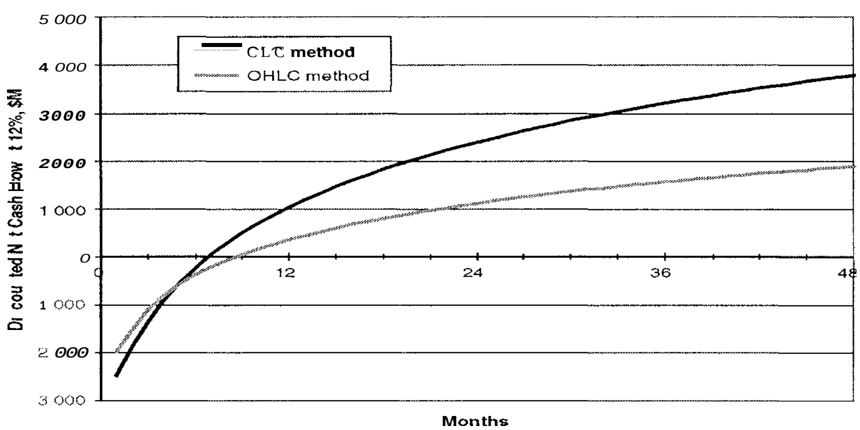


Figure 13 - Predicted Cash-flow Comparison for Flank Wells

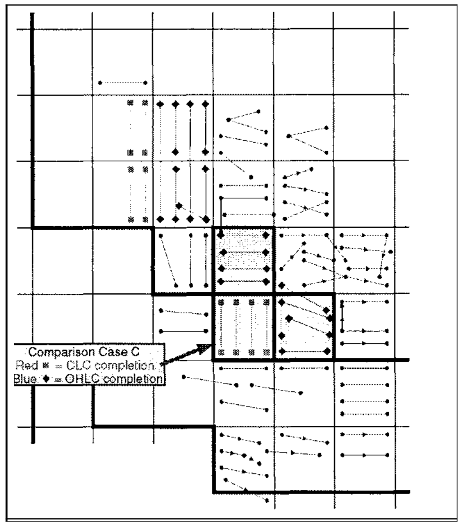


Figure 14 - Completion Camparison for infield Wells

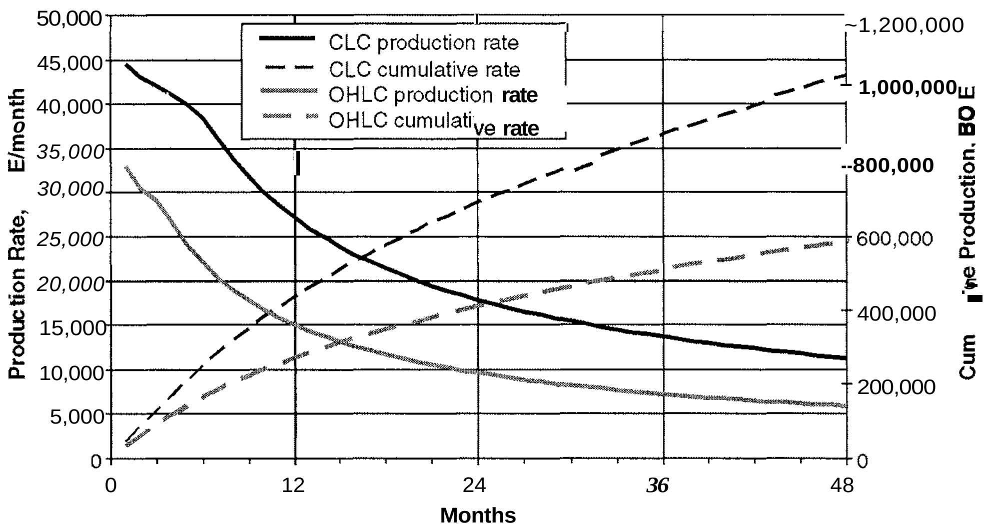


Figure 15 - Production v Results Comparison for Infield Wells

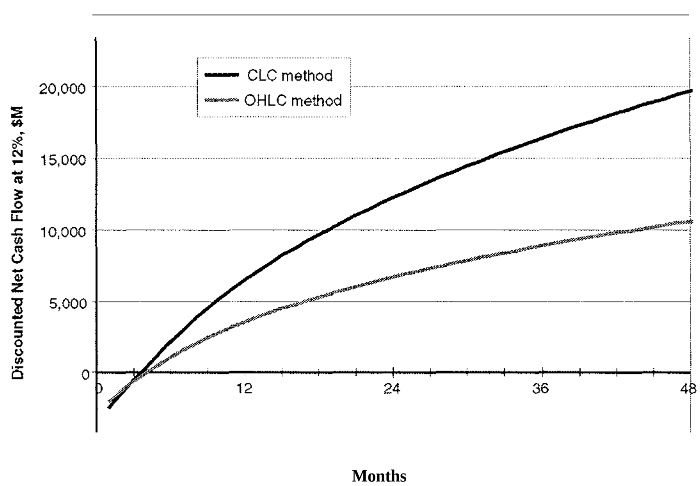


Figure 16 - Predicted Cash-flow Comparison for Infield Wells

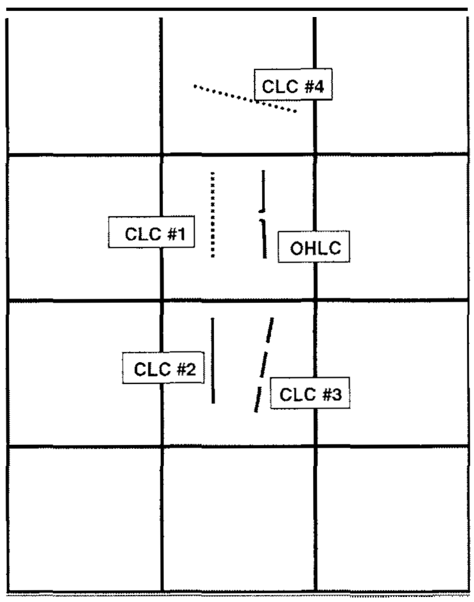


Figure 17 - Relative Well Positions of CLC Wells to Dual Lateral OHLC Wells in Case Study 2

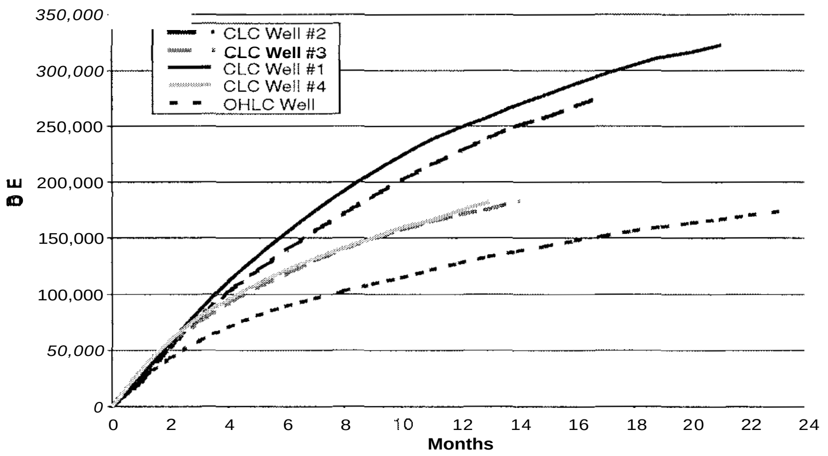


Figure 18 - Cumulative Production Plots for Case Study 2

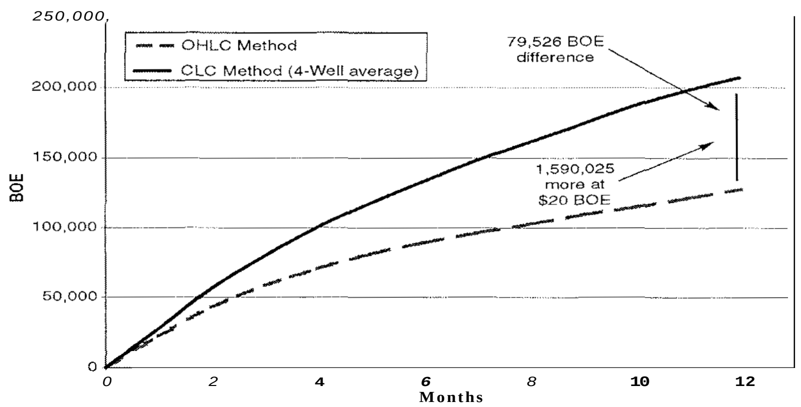


Figure 19 - Case Study 2 One-Year Cumulative Production Comparison for CLC Method (4-well average) and for the OHLC Well