Bottomhole Pressure and In-Situ Stress Profiling Techniques Improve Hydraulic Fracturing in a Secondary Recovery Unit

James L. Rodgerson, BJ Services Company
Raymond L. Johnson, Jr. S.A. Holditch & Associates

Abstract

In-fill development within mature producing fields has been increasing throughout the Permian Basin, West Texas. Stimulation of new wells and recompletion of present producers and injectors many times accompanies this in-fill development. Most recent studies have focused on the overall strategy of in-fill development from a petrophysical characterization standpoint. The impact of hydraulic fracturing within a secondary recovery project has not been as thoroughly investigated as to benefits in production enhancement and overall field development.

Before the effectiveness of hydraulic fracturing in the secondary recovery processes can be fully evaluated, the processes involved in effectively designing hydraulic fractures in this environment need to be addressed. Hydraulic fracturing is complicated by the lack of historical data. Treatments in these fields have often been "cook-booked" and given less attention due to their smaller size and scope. Many times the process is further complicated by the interative nature required in effective treatment modeling (i.e. historical review, candidate selection, pre-job design, pre-job diagnostics, on-site or post-job modeling, and post-job diagnostics). In this paper, we will outline the steps required to improve the process without expending excessive resources, and we will discuss the steps where streamlining the process is warranted without compromising the end result. Finally, we will document several cases illustrating effective use of these technologies to obtain more effective stress profiles and more efficient fracture treatments.

Introduction

In-situ stress profiling has long been known to play a key role in fracture geometry determination of modern 3D simulators.[1-3] Much has been written about the importance of acquiring reliable data to calibrate fracture simulation. With the advent of more powerful computers and modeling, data gathering is of paramount importance to insure simulation accuracy. In recent years, skepticism concerning the full capabilities of these models has increased because of the seemingly overwhelming task of collecting adequate data to operate them.[4] We hope to demonstrate some very practical techniques that can be utilized effectively to fine-tune fracture simulations without spending an extraordinary amount of time and money preparing the data sets.

There are many methods available today to determine formation rock properties such as Young's Modulus, Poison's ratio, permeability, etc. These methods range from core analysis to advanced logging techniques.[5,6,7] Each of these techniques has advantages and disadvantages as well as economic impact on the producing properties involved. For in many in-fill projects in mature fields, economics is a key concern due to the nature of production. Water disposal costs as well as any pre or post-job diagnostics must be strategically executed to achieve maximum benefit. Many of us tend to believe that any type of advanced analysis would be too costly in these scenarios; in addition, the recovery time for each value-added cost must be quantifiable and achievable. Without good planning or foresight, large amounts of money may be spent on this type of data collection. Although this type of data can prove itself invaluable, by gaining a better understanding of rock mechanical and depositional environments, the pocketbook ultimately must measure success.

Background

It is a well documented fact that hydraulic fracturing of injection as well as producing wells can improve sweep efficiency as well as production.[8,9] In addition, the equations and methodologies to quantify production improvements from hydraulic fractures have been well documented.[10,11] The techniques outlined in this paper have become relatively common in oil and gas producing areas throughout the world, mainly due to the efforts of the Gas Research institute (GRI) in conjunction with the Advanced Stimulation Technology (AST) development process.[12] These advances in stimulation technology have lead to the wide spread use of sophisticated techniques that enable operators to more easily implement these technologies in a more economic fashion. This paper will attempt to describe these techniques and how they have proven an effective tool within the economic guidelines dictated by the production characteristics of a mature in-fill production area. During the initial development of the case study area, much of this type of technology was either nonexistent or extremely cost prohibitive when available.

Design Considerations

The cases represented in this manuscript will focus on the use of data that was readily available. We will discuss important and available data that can be obtained even when funds are limited. In each case we will discuss how and why the data sets were derived. These cases will show how pore pressure and pressure depletion can affect fracture propagation and height growth. These effects are well documented and will be affirmed throughout this paper.[13,14,15]

Prior to beginning the preliminary design, a careful analysis was performed comparing offset sonic data with the target well; these sonic values were correlated to an offset well based on depositional environment and lithology. These comparisons were performed in conjunction with the operator's geological staff. Based on this information, initial stress values were calculated with the assumption of relatively constant pore pressure gradients. This information was then used as input for 3D-fracture simulation. Pump-in tests were performed to calibrate the model real-time. Radioactive tracers were utilized to confirm the design and any conclusions based on post-treatment history-matching with the 3D model.

In-situ stress in the dominant factor controlling fracture containment.[1,16] Stress values may be calculated using the following equations from ether field or laboratory sonic data. These dynamic data may need to be calibrated to match static conditions. Several methods have been derived in to correlate dynamic to static stress values,[17] but even these data may not truly represent the value of in-situ stress. In order to truly calibrate stress we must take these assumptions to the field and correlate them to real-world values. Prior to calibration, any data should be the subject of intense scrutiny due to the inherent variability of data.

From compression and shear sonic velocities (v_c or v_s, ft/μsec) or sonic travel-time data (Δt_c or Δt_s, μsec/ft)[18,19] rock-mechanical properties such as Poisson's Ratio (ν), Young's Modulus (E), Shear Modulus (G), and Lame's Coefficient (λ) can be calculated using the following equations:

$$\nu = 0.5\,(v_c^2 - 2v_s^2)/(v_c^2 - v_s^2) \qquad (1)$$

$$E = 1.34E{+}10\,(\rho v_s^2)\,(3v_c^2 - 4v_s^2)/(v_c^2 - v_s^2) \qquad (2)$$

$$G = 1.34E{+}10\,(\rho/\Delta t_s^2) \qquad (3)$$

$$\lambda = 1.34E{+}10\,(\rho/\Delta t_p^2) - 2\,(G) \qquad (4)$$

$$\nu = \lambda/[2(\lambda + G)] \qquad (5)$$

$$E = G\,(3\lambda + 2G)/(\lambda + G) \qquad (6)$$

In the absence of dipole or arrayed sonic or shear wave travel times, correlations have been derived that may be used to approximate rock-mechanical properties based on compressional travel times along with lithology and density information (Figs. 1&2).[25] In many areas, compressional data may be available from older logs and can be compared with offset wells that have more modern dipole or arrayed sonic logs.

Once Poisson's Ratio has been obtained, the minimum horizontal stress may be calculated using the following well-documented relationship.[3,20,21]

$$\sigma_h = [\nu/(1-\nu)](\sigma_v - P_p) + P_p + \sigma_t \quad (7)$$

Where (σ_v) = overburden stress, (P_p) = Pore Pressure, (ν) = Poisson's Ratio and (σ_t) = tectonic stress. The above relationship can be used as an estimate for initial in-situ stress in preliminary simulations. This relationship should be calibrated based on post job history matching or pre-job diagnostics.[22] Adjustments may be made to account for changes in pore pressure, regional tectonic strain, poroelastic effects, thermal effects, etc. A detailed discussion of tectonic and thermal effects have been well documented by Blanton and Olson.[23] Such effects have been reported to play a dominant role in other secondary recovery optimization strategies.[24]

Reservoir Pressure Profiling

There are many different methodologies to obtain values of reservoir pressures. One method to obtain reservoir pressures is with a wireline conveyed, multiple-setting, pressure-testing device. This type of tool can allow for several tests to be performed in sequence. However, adequate tests should be planned to obtain the necessary profile information as hole conditions can cause some test failures (i.e. poor tool isolation, leaking bladder assemblies and communication of fluid around isolation bladders). Another method to obtain average and idealized reservoir pressures is with transient pressure testing. In some cases this data may be compared to an offset well and corrected based on dip-in gradients (i.e. the fluid level in the target well could be used to calculate reservoir pressure). However, when the fluid level does not remain at the surface, the reservoir pressure may be estimated from the equilibrated fluid level following different completion events. Reservoir pressures obtained by these data can be correlated with other completion data and past transient pressure tests performed in an area. Thus, a qualitative idea of the state of depletion could be determined without incurring excessive cost or extensive testing. A more robust yet inexpensive methodology to obtain pressures in each interval could involve fluid slugging in a similar manner to that performed with fluids and nitrogen in groundwater hydrology, coalbed methane, and tight gas reservoir testing.[26,27,28]

Case Studies and Examples

An in-fill optimization program was initiated in a West Texas San Andres unit to improve flood patterns and recover bypassed oil. Previously, the typical job design **(Table 1)** consisted of 40,000 lbm of 20/40 and 12/20 mesh proppant placed in 22,000 gals fluid. Approximately a 27% vol./vol. pad was used and treatments were pumped at about 11 bbl/min. Normally, these treatments were placed with little incidence of screen-out, but the lease operator was interested in reducing water cut without compromising oil production. Thus, a fracture treatment optimization project began with the goal of better focusing on stimulation treatments in intervals of lower water saturation to decrease water-oil ratios (WOR).

Originally, frac treatments in this field had largely been based on a "cook-book" design. Early in this optimization process, treatments were modeled assuming the pore pressure gradient was constant due to the large amount of water injected and the maturity of the field. Based on a desire to improve the outcome of fracturing treatments, the operator began an extensive program to profile permeability and in-situ stress values using a synthesized log process incorporating new well and offset well information or historical data. Eventually, greater consideration was given to the reservoir pressures for input into the stress model. The values for reservoir pressures were derived from pressure transient tests performed in offset wells and confirmed by pre-treatment fluid level tests following pre-frac injections or acid breakdowns. Finally, it was decided that prefrac pump-in tests should be used to confirm the original stress profiles and to calibrate the 3D, multilayered fracturing simulator (a "lumped parameter" 3D fracturing simulator) used in this case study.[29]

Post treatment radioactive isotope tracer and temperature surveys were used to confirm the 3D fracturing model estimates, (i.e., the treatment pressure history-matching confirmed pre-job parameters excepting for leak-off).[30,31] Whenever changes were required in the data to achieve closer bottomhole treating pressure (BHTP) history-matches in the 3D fracturing model, the geological model was first revisited. BHTP history-matches presented throughout this synopsis do not contain any additional changes from the default settings of the fracturing model excepting for the implementation of multilayer leakoff to use the data from the geologic model.

This iterative process of post-treatment evaluation and better log modeling produced two modified frac treatment designs, which were applied to the field **(Tables 2 and 3).** The first new design used a lower rate (8 bbl/min) and consisted of a gelled-water pre-pad with 100 mesh sand, to help prevent downward growth, followed by an organoborate crosslinked guar (organoborate) system containing approximately 11,000 lbm 16/30 mesh Brady sand **(design "Type 1", Table 2).** The second design also utilized the lower injection rate, gelled water pre-pad with 100 mesh sand, and an organoborate fluid system. However, this second design increased the proppant to a total of 20,500 lbm 16/30 mesh Brady sand, **(design "Type 2", Table 3).** It was hoped that by lowering the rate and using 16/30 mesh proppant, better fracture containment would result. The reduction in sand sizing from 12/20 to 16/30 mesh was implemented with the idea that sand bridging in the fracture may cause excessive height growth; although no pressure charts had indicated excessive height growth, transmissibility effects could mask such behavior.[32]

On the first treatment **(Well A, Type "1" treatment)**, real-time treatment analysis was utilized to calibrate the model.[33] However, no modifications were made immediately to the preliminary fracture design other than to calibrate stress correlations to match the observed real-time, net-pressure data **(Fig. 3)**. After the first job, "real-time" analysis ceased and data was retrieved from the field on a job-by-job basis for post-treatment evaluation. Through, this series of iterative designs, tracer evaluations, and post-treatment BHTP history-matches, the importance of depletion begin to emerge as a major variable in history-matching the BHTP and successfully modeling the observed propped fracture dimensions. Reservoir pressure depletion appeared to aid the objective of focusing the entire treatment in the main pay intervals. It was hoped by achieving this goal that the new treatment procedures would result in better WOR.

Following implementation of the treatment modifications, little difference was noted in initial or 30 day production results **(Table 5)**. However, after evaluating production on seven wells after 90 days (i.e., the total of wells at the time of publication), there appeared to be an improvement in total oil production and a reduction in WOR **(Table 6)**. It should be noted that even if there was only a marginal production increase, there was a benefit to the operator through this optimization process by an overall reduction of job sizes and associated costs. Next, we will outline the processes used to establish and monitor the effectiveness of treatment designs in this in-fill development.

<u>**Well A.**</u> Pre-Frac pump-in tests were performed to confirm the original stress profiles and calibrate a real-time 3D-fracture simulator. This was also the first application of the new smaller, lower rate treatment modifications **(Type "1", Table 2).** No immediate modifications were made on location to the preliminary fracture design other than to calibrate stress correlations to match observed real-time net-pressure data. The treatment pressure history-matching confirmed pre-job parameters excepting for post-frac leak-off **(Fig. 3)**, although the leak-off calculations seem to match adequately during the injection test. Post-treatment radioactive tracers and temperature surveys appeared to confirm that the treatment was confined within the intended pay interval **(Fig. 4)**. The 3D model estimated more upward growth but correctly matched the lower boundary. As a result of the treatment modification on this well an improved WOR was observed when compared to offsetting wells and seem to have long-term production improvement **(Table 5)**. AS this was the first treatment, the first inclination was to believe that

more fracture containment, away from known underlying water-bearing intervals, was achieved by lowering the treatment's volume and injection rate. Any additional upward growth is believed to have healed without being propped or was not penetrated by proppant due to width restrictions in the fracture.

Well B. Based on the success of the previous treatment, the next design also began with the assumption that a constant pore pressure gradient was being applied vertically through the system. This was also the first of the larger-sized treatments **(Type "2", Table 3)**, still using the lower rate design from the previous well (8 bbl/min). However, it was apparent from post-treatment history-matching of the RA (radioactive) tracer log that better containment was achieved. The first explanation was that a lower pore pressure should have been used to account for reservoir depletion in the zone of fracture initiation. This would have corrected the additional height predicted by the model **(Fig. 5)**. After including reservoir depletion effects, the 3D-fracture simulator began to predict more comparable height growth to the post-treatment RA tracer log. This fundamental change in the assumptions began to enable the results of the geologic and fracture models to more accurately predict height growth and closure stress in future simulations. Like Well A, improved production was the result, as compared to previously fractured offsets **(Tables 5 and 6)**. Better long-term production stability and a lower WOR indicated that the treatment did not break into water-bearing segments of the lower interval.

Well D. In well D, it was decided that for comparison purposes a previous style treatment should be pumped to confirm the benefit of the treatment modifications **(i.e. Table1)**. This meant that synthetic log simulations and 3D fracturing models were not implemented. The post-frac production test from this well showed nearly a doubling in the initial WOR as compared to the modified designs, and the longer-term results were similar to previously used treatments **(Table 5 and 6)**. The operator then returned to the modified designs that had improved economics and production.

Well F. This treatment was performed recently using a Type "2" design **(Table 3)**. Following the design improvements, a variable pore pressure component was used in all stress calculations. The results were better calibration of the geologic model, more fracture containment, and BHTP history-matches in the 3D frac simulator. Post-job RA surveys confirmed the results obtained from the application of fracturing and geologic models with the greatest accuracy to date. The resulting BHTP history-matches and modeled dimensions presented in **Figs. 6 and 7** required no modification from original design inputs. Post-treatment BHTP history-matching had proven to be predictive after successive iterations with a geologic model, fracturing model, and post-treatment evaluation tools. Initial production results showed an improved WOR, but long-term production is not available at the time of publication. The treatment did not appear to prop into the water-bearing, lower interval. We will continue to evaluate the effectiveness of the new completions through post-treatment BHTP history-matching, evaluating height growth with post-treatment surveys, and by tracking initial production and long-term WOR.

Conclusion

In conclusion, these case studies present the effective use of advanced fracture modeling techniques without excessive time or resources expended on data collection. Spreadsheet-based mechanical property calculations incorporating offset sonic data were adequate to achieve a better idea of the key elements affecting in-situ stress and layering. Generally, the data gathered for this project has been inexpensive and simple to acquire, especially in an ongoing process. This study exemplifies the importance of fundamental data collection and routine analysis during an ongoing field process such as fracture stimulation improvement.

Recommendations

The following recommendations can be made with respect to the application of these technologies to other in-fill developments, whether secondary or primary. These recommendations are based on understanding and developing a "total" reservoir-based data set for fracturing. These stages would include:

1. The collection of base properties from base well(s) such as rock-mechanical properties, reservoir properties, fluid properties (where critical), open hole logs, fracture identification logs (where applicable), core information, etc.

2. The collection of verification data that can be correlated across future wells from the base well(s) such as; pressure transient tests, microseism fracture mapping, tiltmeters, fluid level tests, surge tests, injection tests, mini-fracs, etc.

3. Collect periodic samples of base properties and verification data throughout initial development.

4. Iterate through all modeled processes simultaneously (e.g. geological, fracturing, reservoir) based upon firm assumptions; limit extraneous variables which are not verifiable or are not consistently observed across the data set.

5. Develop a field-wide or project-based strategy and decision-making process for stimulation improvement.

We have incorporated many of these recommendations into a workable completion routine for this field. Additional treatment designs and evaluations of fracture treatment performance can be executed with ease. In a sense, we have modernized the kitchen and the revised the "cook-book."

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Nomenclature

ν = Poisson's Ratio (dim)
v_c = Sonic Compressional Wave Velocity (ft/μsec)
v_s = Sonic Shear Wave Velocity (ft/μsec)
ρ = Bulk Density (g/cc^3)
E = Young's Modulus (psi)
G = Shear Modulus (psi)
λ = Lame's Coefficient (psi)
Δt_p = Sonic Compressional Wave Travel Time (μsec/ft)
Δt_s = Sonic Shear Wave Travel Time (μsec/ft)
σ_h = Minimum Horizontal Stress (psi)
σ_v = Overburden Stress (psi)
σ_t = Tectonic Stress (psi)
ε_x = Elastic Strain (μstrains)
α = Biot's Constant (dim)
ϕ = Porosity (decimal)

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Table 1
Typical Treatment (Pre-Modification), (Injection Rate - 11 bbl/min)

Fluid		Proppant			
Volume (gal)	**Type**	**Concentration (lbm/gal)**	**Stage (lbm)**	**Cumulative (lbm)**	**Mesh Type**
1000	Freshwater	Pre-Pad		Pre-Pad	
6000	Monoborate Crosslinked Guar	Pad		Pad	
3000	Monoborate Crosslinked Guar	1	3,000	3,000	20/40
3000	Monoborate Crosslinked Guar	2	6,000	9,000	20/40
3000	Monoborate Crosslinked Guar	2	6,000	15,000	12/20
3000	Monoborate Crosslinked Guar	3	9,000	24,000	12/20
4000	Monoborate Crosslinked Guar	4	16,000	40,000	12/20

Table 2
I Treatment "Type 1" (Post Modification), (Injection Rate - 8 bbl/min)

Fluid		Proppant			
Volume (gal)	**Type**	**Concentration (lbm/gal)**	**Stage (lbm)**	**Cumulative (lbm)**	**Mesh Type**
1000	Guar Gelled Water	0.5	500	500	100
1000	Organoborate Crosslinked Guar	0.5	500	1,500	100
1500	Organoborate Crosslinked Guar	Ramp 2 to 5	5250	6,250	16/30
1000	Organoborate Crosslinked Guar	5	5,000	11,250	16/30

Table 3
Treatment "Type 2" (Post Modification), (Injection Rate - 8 bbl/min)

Fluid		Proppant			
Volume (gal)	**Type**	**Concentration (lbm/gal)**	**Stage (lbm)**	**Cumulative (lbm)**	**Mesh Type**
1000	Guar Gelled Water	0.5	500	500	100
2000	Organoborate Crosslinked Guar	0.5	1000	1500	100
3000	Organoborate Crosslinked Guar	Ramp 2 to 5	10,500	12,000	16/30
2000	Organoborate Crosslinked Guar	5	10,000	22,000	16/30

Table 4
Summary of Treatments during Optimization Process

Well Desc.	Treatment Type
A	Modified "Type 1"
B	Modified "Type 2"
C	Modified "Type 1"
D	Pre-Modification Type
E	Modified "Type 1"
F	Modified "Type 2"

Table 5
Production Results

Wells	Pre-Frac Production			Initial Production Results (After Frac)			30 Day Production Results		
	Oil (bbl/day)	*Water (bbl/day)*	*WOR*	*Oil (bbl/day)*	*Water (bbl/day)*	*WOR*	*Oil (bbl/day)*	*Water (bbl/day)*	*WOR*
Unmodified Treatments									
Before Modifications	N/A	N/A	N/A	26	437	16.8	43	354	8.23
Before Modifications	N/A	N/A	N/A	48	150	3.13	68	85	1.25
Before Modifications	N/A	N/A	N/A	54	289	5.35	38	109	147
Well D	8	8	1.00	23	178	7.74	26	111	4.27
Avg.- Unmodified Jobs				***38***	***264***	***6.98***	***44***	***165***	***3.77***
Modified Treatments (Both Types)									
Well A "Type 1"	14	106	7.57	17	293	17.2	67	364	5.64
Well B "Type 2"	23	80	3.47	52	142	2.73	56	114	2.04
Well C "Type 1"	15	51	3.40	43	389	9.04	29	121	4.17
Well E "Type 1"	9	29	3.22	47	270	5.74	21	129	6.14
Well F "Type 2"	N/A	N/A	N/A	24	223	9.29	57	145	2.55
Avg. "Type 1" Treatments	*13*	*62*	*4.76*	*36*	*317*	*8.90*	*39*	*205*	*5.24*
Avg. "Type 2" Treatments				*38*	*183*	*4.80*	*57*	*130*	*2.29*
Avg. All Modified Jobs	***15***	***67***	***4.36***	***37***	***263***	***7.20***	***46***	***175***	***3.80***

Table 6
Production Results, Case Study

Wells	90 Day Production Results		
	Oil (bbl/day)	*Water (bbl/day)*	*WOR*
Avg. Jobs (4) Unmodified	35	196	5.63
Avg. Jobs (3) Modified	44	147	3.31

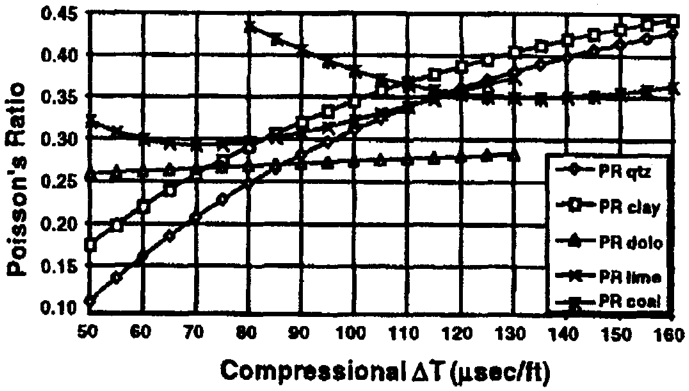
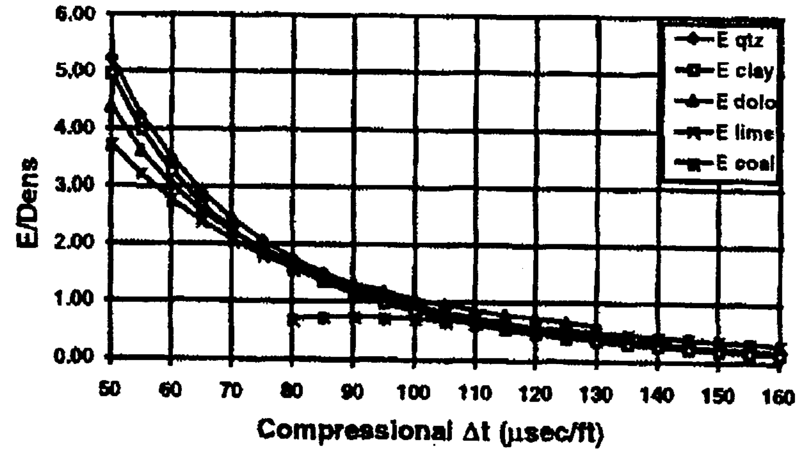


Figure 1 - Correlation, Poisson's Ratio versus Compressional Sonic Travel Times



Note: Multiply E/Dens by Bulk Density (g/cm³) to get Young's Modulus in 10^6 Psi

Figure 2 - Correlation, Young Modulus versus Compressional Sonic Travel Times

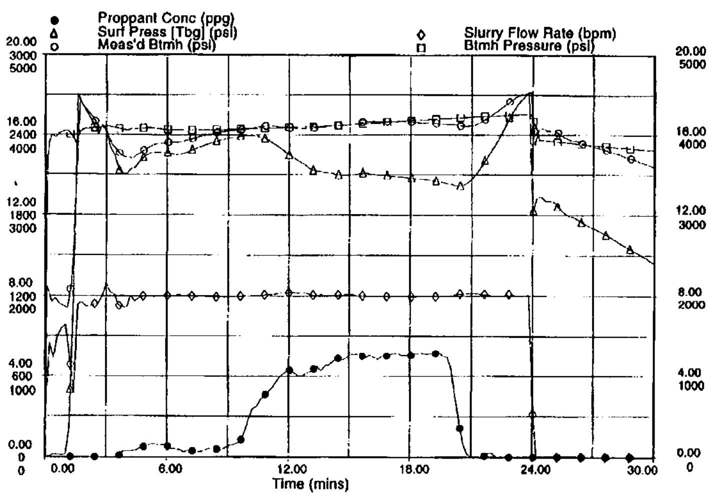


Figure 3 - Well A- Treating Pressure History-Match

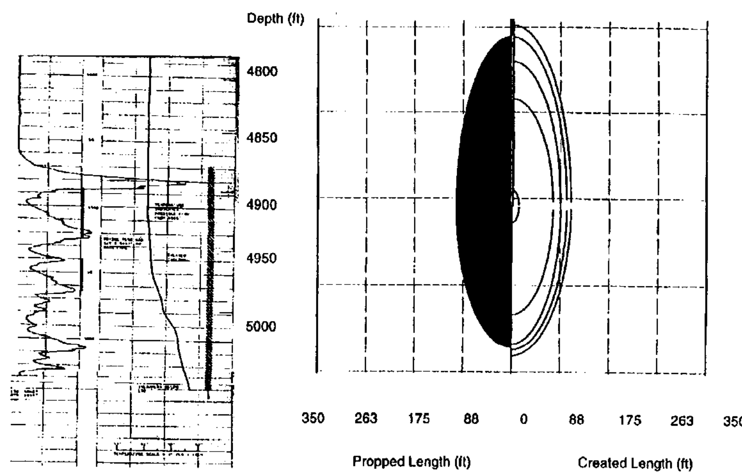


Figure 4 - Well A- Post-treatment Radioactive Tracer Log vs. Fracture Model Output

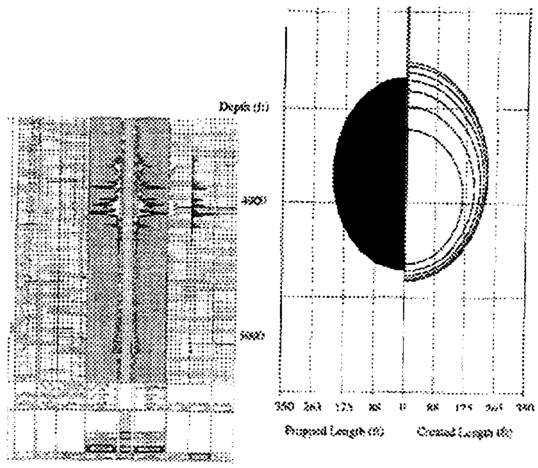


Figure 5 - Well B- Treatment Radioactive Tracer Log vs. Fracture Model Output

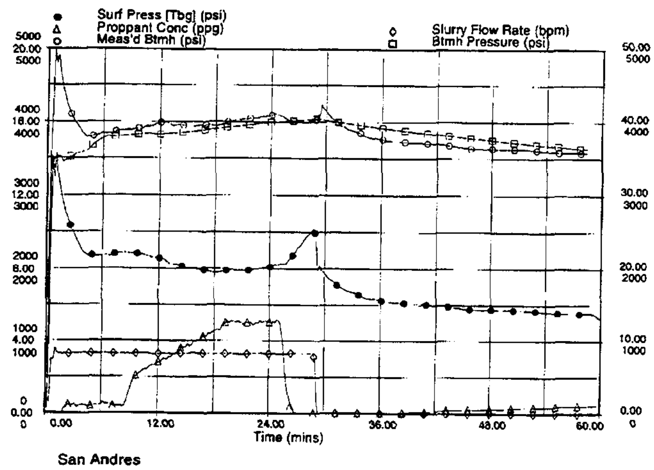


Figure 6 - Well F- Treating Pressure History-Match

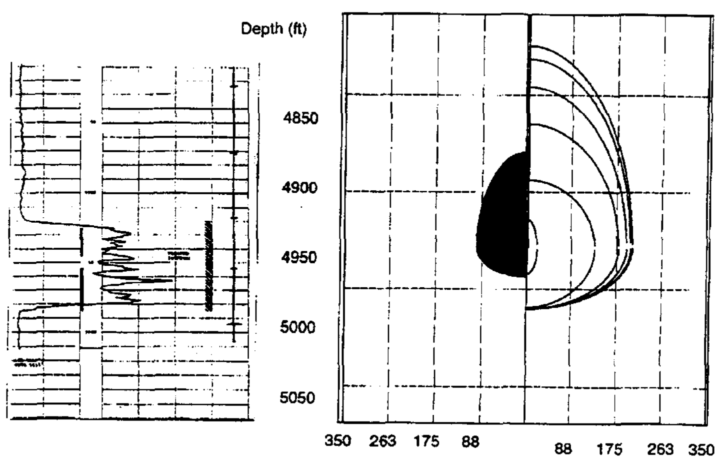


Figure 7 - Well F- Post Treatment Radioactive Tracer Log vs.
Fracture Model Output