FRACTURE MONITORING USING "LOW COST" PASSIVE SEISMIC

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Abstract

Passive seismic measurements were taken before, during, and after a fracture stimulation treatment to monitor the fracture growth and optimize future fracture treatments. The seismic events created by the fracture treatment showed an asymmetrical east-west trend during the treatment, with wide variations in the locations of events. The passive seismic measurements support the previous belief that the fracture orientation for the field is east-west. However, the recorded events showed more complexity to the fracturing process than had been anticipated. The events showed a southwest trend toward a producing well along with the widely scattered events to the east. Neither, the 3D fracture simulator, pressure transient analysis, nor production injection data supports the very large fracture geometry of the passive seismic events.

Fracture lengths and heights from the passive seismic events varied along with the directions. The length of the wing to the southwest showed seismic events over 1200 feet from the well, while the east wing events only reached about 700 feet. The different wings also showed a large variation in the height of events. Although the treatment interval was 4820-4910 feet, seismic events occurred from 4550-4900 feet for the southwest wing and 4600-5008 feet for the east wing. The shorter length to the east is believed to be due to the well being offset to the east, by another injection well. The higher pore pressure, from the water injection, caused the fracture pressure to increase, thereby changing the direction of growth of the fracture.

The passive seismic results show that fully modeling the fracture process will need to incorporate a simulator that allows varying fracture parameters aerially as well as vertically. The 3D model, of the initial 1966 fracture treatment, showed a propped fracture length of 139 feet, with a propped area of 29,000 square feet. The prefracture falloff, which followed running a liner and a cement squeeze, showed an area of 15,000 square feet. The second 1995 treatment model results gave a length of 150 feet and an area of 26,000 square feet. The values for the last job match very closely the pressure transient results following the treatment, of 24,000 square feet, showing that the current model can predict fracture results adequately for most evaluation purposes. However, for nonuniform pressure gradients a more detailed areal model will be needed.

Introduction

Passive seismic measurements were taken as part of the joint project by OXY USA Inc. and the Department of Energy (DOE) at the West Welch Unit(WWU) to improve fracture treatment design. Passive seismic events are recorded from the micro earthquakes, created by the movement of the formation, resulting from the hydraulic fracture treatment. The movement can occur as the fracture is widened or as the fracture closes.

The Welch field is located in the northwestern portion of Dawson county, Texas, and produces from the San Andres formation at average depths of 4800'-4900'. The field was discovered in 1936, with waterflooding initiated in 1958, reaching full field implementation by 1972. The Unit has been further developed by infill drilling and pattern modification, and is currently producing from 20-acre line drive patterns, with some areas where the infill injectors have not been drilled. The southern part of the DOE project area (Fig. 1) shows an example of this.

Wellhead injection pressures have varied over time, from 400-1800 psig. The current injection pressure is about 1600 psi, which is at, or slightly above, formation parting pressure. Due to the high injection pressures, fractures at injection wells were initiated. In addition, propped hydraulic fracture treatments, to increase injectivity, have been performed on a large portion of the injection wells. Water breakthrough and pressure testing showed fractures were generally oriented east-west, causing the current line drive pattern arrangement. As a result, a plan, to take advantage of the fracture orientation, to increase sweep efficiencies was made a part of the DOE project proposal. As a part of the plan, the passive seismic measurements were made on the WWU #4807, during the 1995 fracture treatment of the well, to compare to the fracture model results. The #4807 was chosen for the analysis, after an initial data review was made, and all the wells in the project area, on the wider spacing, were found to have been hydraulically fractured. Data gathering and analysis included evaluation of well log, core, and pressure transient data that was then incorporated into the 3D fracture model. The 3D fracture model was built, then refined, through history matching the well's previous treatments, and production and injection volumes for the #4807, and offset wells. Changes to the model were made, based on the available information, to arrive at a final model for designing the new fracture treatment. The designed treatment was pumped with tagged injectants, while seismic events were recorded in an offset well. Post fracture analysis included, (1)using the 3D model, (2)logging to evaluate the tagged injectants and fluid injection intervals, and (3)falloff testing to determine the effective fracture area after closure.

Prefracture Analysis and design

Well log and core data from area wells was used to setup the initial 3D fracture model, with most of the data indicating the fracture would grow out of the pay interval. Results of the Full Wave Sonic (FWS) log showed the layer stresses (Fig.2) would cause the fracture to grow down, into the water zone below the main pay. This was supported by core testing samples taken from different intervals (Table 1.), and the match of fracture pressures, obtained from the FWS, with step rate test results. The fracture pressure, obtained from the FWS analysis, was 3200 psig; while, the step rate results gave a fracture pressure of 3150 psig.

Injection surveys prior to the treatment showed wide variations in injection intervals. The injection survey, just prior to the treatment (Fig 3), showed 50 percent of the water injection going into the very top of the perforated interval, 25 percent was going into the middle of the interval, and 25 percent going into the bottom. Earlier surveys indicated injection was better distributed over the main pay, corresponding with the balanced injection and production of total fluids that was seen for the area. If significant volumes of water were leaving the pay interval, injection-production ratios would not be 1:1. Permeability values are less than .01 md above the N marker (Fig. 3), a dense, primarily anhydrite, interval; therefore, any injection volumes above this interval would be negligible. The lower water zone, however, does have good permeability and significant injection volumes could be lost into this interval.

The 3D model appears to give a good representation of the final propped fracture area of the 1966 fracture treatment, although the calculated height is questionable. The model shows a fracture area of 29,000 square feet remaining after fracture closure, compared to the falloff test results of 15,000 square feet in 1995. The difference is due to setting a liner, and a cement squeeze in the mid 70's. A fracture length of 139 feet, and a fracture height of 208 feet at the wellbore, is calculated by using the model. Data described previously indicates injection is in the main pay interval, and does not support the model, which shows the fracture being propped out of the main pay interval. If the height, calculated by the model, is shortened, the result would be a longer effective fracture in the pay interval. The longer fracture length is supported by a lack of passive seismic events within 200 feet of the wellbore from the refracture treatment and the results of the falloff testing showing a longer propped fracture.

After the previous treatment was shown to grow out of zone with the 3D model, the new fracture treatment was designed to place proppant in the main pay interval, and keep it out of the lower water zone. The resulting treatment (Table 2) used a high density pad, followed by low density, nitrogen foamed stages of 20/40 mesh sand, pumped at eight barrels/minute. The purpose of the foam was to utilize density override, to place the sand higher in the fractured interval away from the water zone, and still, obtain as much propped length as possible after fracture closure. The water zone was estimated to be 45 feet below the bottom perforation, separated by a dense, impermeable zone. The bottom barrier is the interval from N8-N9 in Figures 2 and 3. Fracture growth upward out of zone was not a concern, since there are no zones with permeability, allowing out of zone fluid loss to occur.

Fracture Treatment Results

Passive Seismic. An observation well was used to monitor the seismic events created by the fracturing process. Both the treated well and the observation well had directional surveys run for more accurate bottom hole location. The observation well used, was located 560 feet south of the treated well, and had four geophone stations, spaced 50 feet apart, vertically across the treated interval. Each station consisted of three geophones to measure the X, Y, Z components of events, allowing individual seismic events to be located in three dimensions[1]. Another approach uses the multiple stations, allowing triangulation of the source location[2], using check shot velocities. The velocity check shot, was acquired prior to the fracture treatment, by detonating a dynamite charge in the well to be fractured and listening at the observation well.

Detection. Passive seismic events were recorded before, during, and after the fracture was pumped, with over 200 events identified. Identification of events was made using a band pass filter to distinguish event signals from noise. After visual inspection of the signals revealed only weak signals, a signal detection program was used for finding potential signals. Since a small time lag would be expected between the different stations receiving a signal, a time window was used to find events that created at least four signals. Combining the time window and testing different band pass filters, resulted in finding 229 events in the 0-50 Hz range, which other studies[3] have found to be fracturing event related. Of the 229 events, 30 had at least six detections exceeding a signal to noise ratio of 3.0. Background noise, which masks the events, was higher during pumping, and resulted in almost zero detection rate. The highest detection rates occurred immediately following shutting down pumping, even if the shutin was only for a short time.

Twenty-seven event locations remained, after refining the initial 30 picked. Figure 4 is a 3-D representation of the 27 events. Once the events were found in the records, event locations were calculated from the relative amplitude of the signals and the difference in the shear wave and the P (compression) wave arrival times[4]. The P wave and shear wave should be 90 degrees apart; if the angle varied significantly from 90 degrees, the events were excluded. When different geophones gave greatly different locations, the most common problem was getting the depths to agree. It is believed the interval at 4800 feet, where the velocities differ significantly, caused a large part of this problem.

Interpretation. A plan view of event locations (Fig 5) shows significant variation from a linear symmetrical fracture. The events show a partial east-west trend, as expected from the previous field history discussed in the introduction. The east wing of the fracture created events up to 700 feet away, slightly over ½ the distance to the offset injection well. Since the intent of the hydraulic fracture is to create a buildup of pressure in the pores to fracture the rock, it is expected, the higher pressure of the adjacent injection well stopped the fracture from growing in length, and forced it to widen and/or grow in height. It should be pointed out again, that the well is situated in an east-west line of injectors spaced about 1320 feet apart.

The areal scattering of the events, generated by fracturing, are due to compressive forces as the main fracture is widened. The eastern portion of the fracture was the result of a previous treatment, while the southwest wing resulted from this fracture treatment. More events are located in the SW portion of the fracture, and are more closely spaced than the events to the east. The location of the events to the east are wider spaced, as expected, from a pre-existing fracture, when the initial fracture is widened and associated events are due to compression of the formation away form the fracture. Whether these events are due to simple collapse of vugs, etc., or from creating additional fractures is not known at this time. Further review to determine the origin may be done. Other studies[5,6] have shown that compression can create tensional and shear fractures along the main fracture and these fractures can occur at different angles from the applied compressive force for differing rock ductility. The effect of these fractures on the overall treatment is not known; however, they could be important as a significant fluid loss volume that could be interpreted as height growth on a net pressure plot.

Radioactive tagging, during different stages of the treatment, and post fracture injection surveys were performed to aid in the determination of fracture height. While, the majority of the seismic events out of the main pay occurred above 4800 feet, post fracture logging showed that most of the tagged injectant stayed in the perforated interval, at least near the wellbore. Figure six shows the relative concentration of tagged injectant. The pad was tagged with antimony, the initial stages of proppant with scandium, and the final stage of proppant with iridium. The concentration of the tagged injectants is at background levels, above and below the perforated interval, showing the effective fracture near the wellbore is near the limits of the main pay.

A cross section of the passive seismic measurements (Fig 7), shows height growth initially farther from the wellbore, and later events occurring closer to the wellbore. The deepest event mapped is at 4989 feet, just reaching the water zone below the main pay. As the only seismic event in the water zone interval, it is isolated vertically and aerially, leading to the conclusion that the fracture did not grow down.

There is no indication from logging, injection or production volumes to indicate any fluid is leaving the pay interval. The changes in the injection surveys have shown an increase in the middle of the pay interval to account for the increased injection after the fracture treatment. Since the intervals above the N marker (Fig 5) are mainly dense, tight, dolomites and anhydrites, there was not enough upward fluid movement to deposit significant amounts of proppant out of zone. The water zone below the main pay also appears to have received negligible amounts of proppant. As mentioned above, the additional injection volumes are going into the middle of the pay interval. If the injection water was going out of zone, the surveys should show this, since the reservoir has numerous vertical permeability barriers. The above evidence suggests only a small amount of proppant, if any, was placed out of zone even with the fracture events occurring almost 300 feet above the main pay interval. This supports the prediction that the foamed gel would produce enough of a gravity override effect to keep proppant out of the water zone.

Conclusions

Passive seismic measurements can be used successfully as an aid in fracture design. It can be especially beneficial in determining local fracture orientation. The actual propped fracture lengths and heights depend on fluid movement; thus, layer properties, including permeability, are essential for accurate 3D modeling.

Detection of fracturing events can be enhanced by short shutdowns during the treatments. This would be especially useful as the distance from the treated well to the observation well(s) increase.

Changing formation pressures can cause the fracture orientation to change on subsequent refracture treatments. This is consistent with Mukherjee et, al.[7] Shutting in offset injectors and even flowing wells back may be useful for controlling fracture geometry.

The seismic measurements have shown events that may be the result of additional fractures nearly perpendicular to the main fracture. Further work needs to be done to try to determine if these fractures affect the treatment results.

Multiple observation wells would aid with detection of events, since the receivers would be closer to the sources, as the fracture propagates on different sides of the wellbore.

Post fracture analysis has shown that the foamed proppant was effective in keeping proppant in the desired interval.

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Table1
Core data from lab on the #4852 core.

Depth (feet)	Young's Modulus (psi x 10^{-6})	Poisson's (Ratio)	Compressive Strength (psi)
4836	12.6	.28	24455
4844	6.8	.26	15690
4852	5.1	.35	15324
4866	4.6	.24	10557
4900	9.5	.29	13222
4924	11.9	.28	24014

Table 2
1995 Fracture Treatment Schedule

Stage	Planned Volume (gal)	Foam %	Actual Volume (gal)	Planned Proppant Concentration (lb/gal)	Actual Proppant Concentration (lb/gal)
1	1000	0	453	0.00	0.00
2	1000	0	1011	0.00	0.00
3	840	0	861	0.00	0.00
4	15000	0	14654	0.00	0.00
5	1500	0	1233	0.00	0.00
6	1500	70	1386	2.00	1.77
7	1500	70	1404	3.00	3.07
8	1500	70	1540	4.00	4.48
9	10000	70	3516	5.00	6.03
10	763	0	759	0.00	0.00
Total	33974		26818		

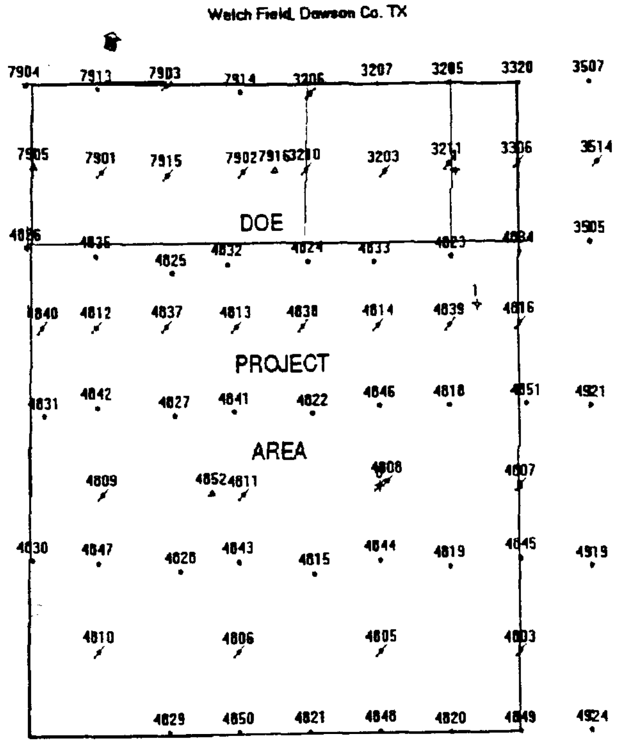

Figure 1 - Map showing a portion of the Welch Field. Injection wells in the south have not been infilled.

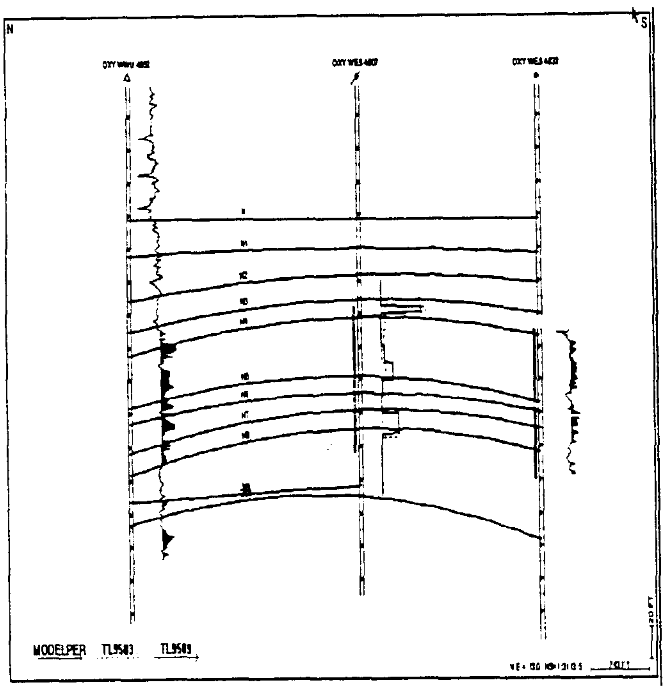

Figure 2 - Cross section showing the layer permeabilities and injection surveys

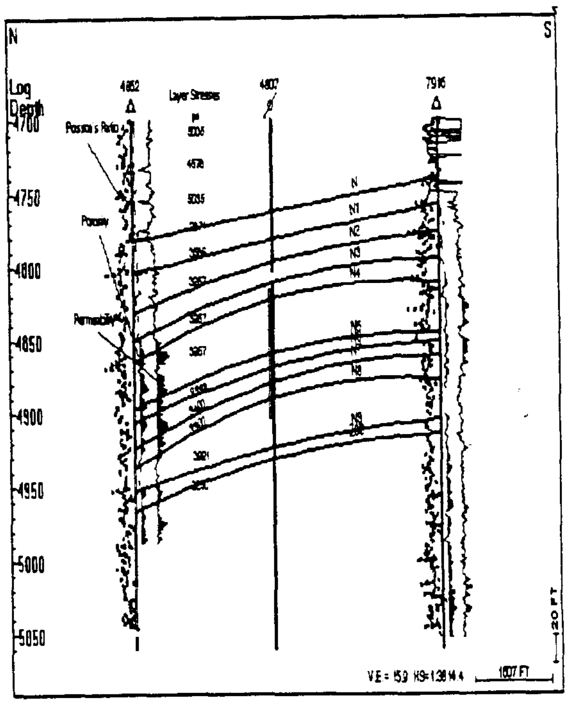

Figure 3 - Layer stresses used in the facture model are shown.

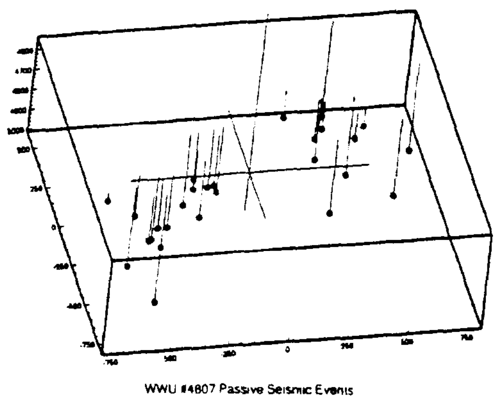

Figure 4 3D representation of seismic events. Vertical lines extend upward from the event to 4500 feet.

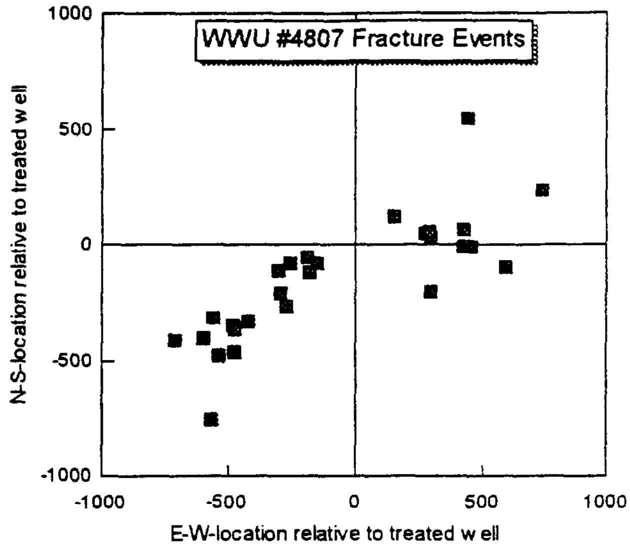

Figure 5 - Plan view of the seismic event locations.

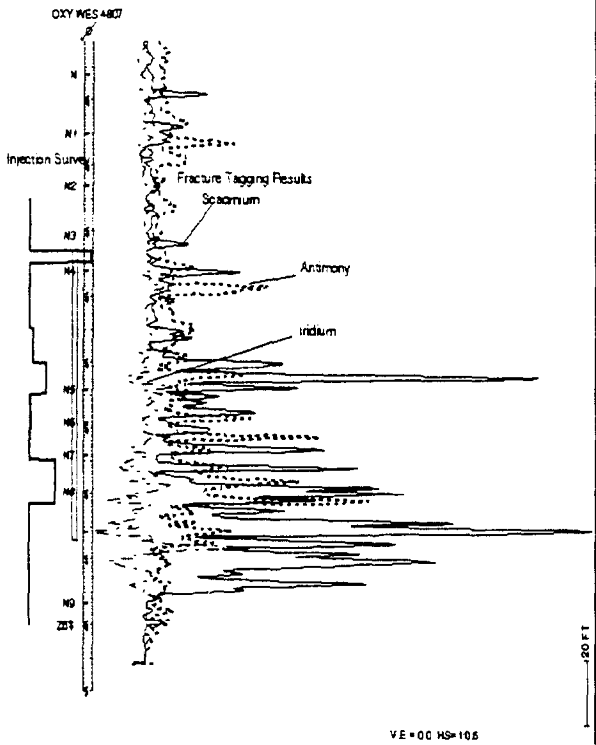

Figure 6 - Concentration of tagged injectant after 1995 frac.

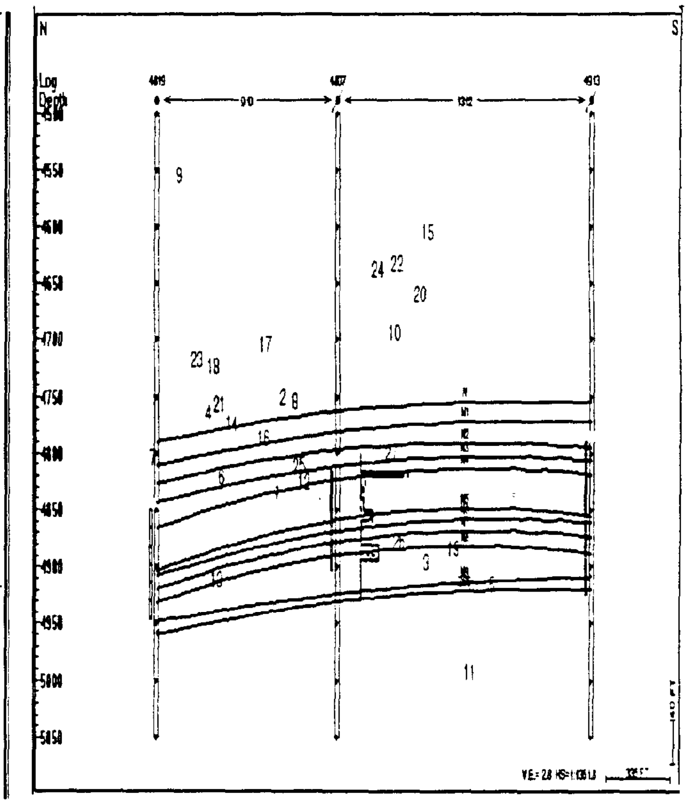

Figure 7 - Cross section of seismic events numbered as they occurred.