A DISCUSSION OF CLUSTER PERFORATING vs LIMITED ENTRY COMPLETION TECHNIQUES

Robert E. Barba, Jr.
Integrated Energy Services, Inc.
Richardson, Texas

Mark A. Linroth
Integrated Energy Services, Inc.
Midland, Texas

ABSTRACT

When an operator is faced with the prospect of fracture treating large pay intervals, several options exist. The most popular technique appears to be single stage limited entry, followed by multiple stages with bridge plugs or baffle rings. With the growing acceptance of 3-D fracture simulators the technique of cluster perforating has provided a third option. The 3-D models often suggest that large intervals can be effectively connected to the wellbore using a single propped fracture initiated from a relatively small perforated interval. This technique is often unpopular with operators who feel that each foot of net pay must be connected to the wellbore with a perforation. Perforating large intervals may lead to the creation of multiple fractures, though, especially when the wellbore or fracture is not vertical. This can be counterproductive to maximizing fracture lengths, particularly when the design assumed a single fracture. Field examples are provided to support the theory of multiple fractures and small interval perforating. A model is then presented to aid in the staging and perforation design process.

INTRODUCTION

Operators frequently encounter multiple zone pays that require fracture stimulation. Fig. 1 is a graphical depiction of the multiple zone situation. Field evidence suggests that when multiple zones are treated simultaneously multiple fractures can be created, with one dominant fracture receiving the majority of the proppant. In some cases this can be advantageous when only the removal of near wellbore damage over a long interval is desired. In moderate permeability or naturally fractured reservoirs limited entry may be the optimum stimulation. If the reservoir produces primarily from low permeability matrix this technique could leave a significant quantity of hydrocarbons behind. These reservoirs benefit from increased fracture length, and if the treatment volume does not allow for the additional fluid lost to these multiple fractures propped lengths could be much shorter than designed.

EVIDENCE OF DEVIATED FRACTURES IN CORE DATA

Hydraulic fracture orientation can be inferred from the orientation of drilling induced fractures and stress test induced fractures with borehole imaging tools.[1] (Fig 2). Similar information can be obtained from oriented cores. Once this information has been obtained the primary focus has been the determination of fracture azimuth to optimize well drainage patterns. While azimuth is an important input from these imaging tools, the fracture dip data acquired at the same time has largely been ignored. Data acquired from several studies suggests that the "vertical" fractures observed with imaging tools are rarely vertical. In terms of fracture dip, these fractures rarely have a dip of exactly 90 degrees. In the GRI Canyon Sands project in the Val Verde Basin of West Texas the Phillips Ward C-11 well oriented core had microfrac stress test induced fractures with a dip of 85 degrees to the NW or 5 degrees off vertical.[2] This was confirmed with acoustic borehole images. In the GRI Staged Field Experiment No. 1 well in the Travis Peak of East Texas, fracture dips observed in cores after 3 stress tests were 89, 90, and 90 degrees, indicating near vertical fractures. In SFE No. 2, however, the dips from seven post-stress test core analyses ranged from 77 to 90 degrees, with an average dip of 85.1 degrees and a median dip of 87 degrees. The SFE 1 tests were from a depth of 5800-6200, while the SFE 2 tests were from 8255 to 9830.[3] A core obtained from a horizontally drilled offset to vertical hydraulically fractured wells in the Lost Hills Field in California by Mobil indicated consistent fracture dips of 15 degrees.[4] These dips were perpendicular to structural dip as well, and multiple fractures were observed. In a similar horizontal core taken at the MWX site in Colorado non-vertical multiple fractures were also observed, along with multiple strands of unbroken crosslinked gel from a treatment 6 years earlier.[5] Lastly, in the Spraberry Trend of West Texas oriented core, acoustic imaging, and electrical imaging techniques indicate the majority of the drilling induced fractures were non-vertical.[6]

These studies clearly indicate that truly vertical fractures in the near wellbore area are the exception rather than the rule in a wide variety of areas. The implications of this to the completion design community are significant. A rule of thumb to keep in mind is that for 1 degree of dip there is 1.75 feet of lateral displacement over a 100 foot interval. If a fracture dip of 2 degrees is assumed, two sets of perforations 100 feet apart would result in two fractures that were separated by 3.5 feet of lateral distance. While these fractures may re-orient to be normal to the maximum principal stress (usually the vertical overburden) once the near-wellbore region is cleared, the initial departure from the wellbore region would increase the probability that the fractures will not intersect and create one fracture. While it is possible that these fractures could intersect under certain geological conditions, it is somewhat unlikely. This assumption ignores the deviation of the wellbore which can exacerbate the situation. This creation of multiple parallel fractures suggests that perforating long intervals could result in pad fluid and initial proppant stages being diverted from the main treatment objective, unless only the main treatment objective is perforated. This could result in design lengths in the main objective zone significantly shorter than expected, with a corresponding loss of production in low permeability matrix reservoirs. On the positive side, if there is more than one main zone stages can be placed closer together without interference. In addition, in naturally fractured reservoirs perforated with limited entry a number of small propped fractures may be beneficial to production rather than one large fracture that may have its proppant concentrated in the lower portion of the fracture.

EVIDENCE OF DEVIATED FRACTURES FROM TRACER AND SPINNER DATA

While the core data and image data are strong indications the above problems could occur, additional verification can be obtained from field tracer surveys. With the advanced tracer techniques, multiple isotopes can be placed in various proppant stages to determine which zones are accepting the various stages. Several field examples presented suggest that multiple fractures are created initially when perforations are widely scattered, with the final stage of proppant being placed in a dominant fracture.

The first example was presented by Holditch, Holcomb, and Rahim from the Tubb formation in Crane County, Texas.[7] Fig 3 is a post frac tracer log from the well alongside a full wave sonic based fracture height prediction log. The initial proppant stage with 63,000 lb of 20/40 Ottowa was tagged with Sc-46 Zero Wash* tracer, while the resin coated tail in-stage was tagged with Ir-92 Zero Wash tracer. The resin coated tail-in was observed in the lowest stress zone only (Zone A), with 60% of the zone taking the proppant. While it did receive a small amount of the initial uncoated proppant stage, the middle and lower zones did not receive any of the resin coated final stage. This suggests that at least three separate vertical fractures were created by the pad, with the lower two stages screening out during the initial proppant stages. Of particular interest is the relatively short distance between Zones A and B (13 feet between perforations). While it is possible that the Zone A and B fractured together and uncoated proppant formed a bank that limited the downward growth of the resin coated proppant, it is also possible that A and B were separate fractures. This has significance in the spacing of perforations, suggesting that intervals should be no more than this distance apart.

The second field example is from the Canyon Sand in the Val Verde basin (Fig 4). The operator elected to perforate two zones limited entry, with the zones separated by 80 ft. of shale and siltstone. The post frac tracer survey suggested that no tracer was placed near the wellbore through the shale in-between the two zones. This in itself suggests multiple fracture creation. A secondary indication can be seen on the treatment pressure response (Fig 5). The surface treating pressure dropped when the hydrostatic head from the addition of proppant was added. There was a rise in the surface treating pressure when the 3 lb sand was entering the perforations, then the pressure continued to drop. Several 3-D fracture modeling runs were conducted using the data, with the best fit assuming that 80% of the pad went into the lower zone and 20% into the upper zone, and that only the 2 lb stage of proppant went into the upper zone.

The third field example was presented by Cleary (et al) from the Cotton Valley in the East Texas [8] (Fig. 6). The operator perforated approximately 500 ft. of interval, and desired to treat this interval with a single stage hydraulic fracture treatment. Prior to pumping the main job proppant slugs were pumped to remove tortuosity, and these proppant slugs were tagged with Iridium and Scandium. The final proppant stage was tagged with Antimony. The post frac tracer survey indicated the main treatment went only into the upper perforations, with the lower perforations screened out with the proppant slugs. A post frac spinner survey was run as well, indicating that 83% of the gas production was coming from the upper portion of the 500 ft perforated interval. This suggests that multiple fractures were created with the pad, and that most of these below the main zone were screened out with the proppant slugs.

The fourth field example was from the GRI Canyon Sands project in Sutton County, Texas. The Lower Canyon interval was perforated over a 143 ft interval, with three separate lobes perforated (Fig 7).[9] A spinner survey was run during the minifracture treatment to determine if separate fractures were being

* Mark of ProTechnics Corporation

created. The survey clearly indicated two separate fractures were being created, with the lower interval taking less fluid as the rate and viscosity increased (Fig 8). The shut in pass with the spinner survey indicated there was significant cross flow between the upper and lower intervals. The distance between the lower two lobes was 28 feet, with a 700 psi stress contrast.

The fifth field example is from the Spraberry trend in Reagan County. The operator ran full wave acoustic logs across the zone, and the Poisson's Ratio distribution suggested the in-situ stress contrast was weak. The field treating pressure data supports this, with the net pressure plots suggesting unrestricted height growth in the area.[6] The post frac tracer survey indicated tracer material near the wellbore 53 feet above the top perforation and 46 feet below the bottom perforation (Fig 9). The borehole deviation through the section indicated a 1/2 degree deviation above the top perforation and a 3/4 degree deviation below the bottom perforation. Core data suggested the fracture dip was 89 degrees, providing a maximum of 1.5 degrees above and 1.75 degrees deviation from vertical. If the fracture began deviating from the wellbore at the top perforation it would be 16.7 inches away from the wellbore where the tracer survey lost track of the proppant. If it similarly began deviating from the wellbore at the bottom perforation it would be 16.9 inches away from the wellbore when the tracer survey lost track of the proppant. This is in the range of published depths of investigation for the tracer surveys, suggesting that the fracture could be migrating beyond the height suggested by the tracer.

MODEL FOR STAGING AND PERFORATION DESIGN

The above field examples suggest that multiple fractures can be created with large perforated intervals and that deviated fractures can occur. Many wells have been completed with large perforated intervals in a wide variety of formations, including the Travis Peak, Cotton Valley, Spraberry/Dean, Canyon Sands, and Clearfork. In many cases economic completions have been made in spite of the inefficiencies resulting from the creation of multiple fractures. In addition, studies have indicated that limited entry designs obtain superior results to non-limited entry completions when large intervals are perforated.[10] The comparisons made in Ref. 10 were between large interval non-limited entry wells and large interval limited entry wells, and no data were available on cluster perforated wells. In the examples presented, the zone with the highest permeability-thickness received the majority of the treatment, and this is most likely the reason for the economic success. This is most likely due to the higher permeability-thickness zones having lower reservoir pressures, as all of the wells were infill development wells. The higher permeability zones within a reservoir tend to deplete faster than the lower permeability zones, and lower reservoir pressure is directly related to lower frac gradients. In all of these cases, though, the main zone received only a portion of the total treatment pumped, with the peripheral zones receiving fluid and the initial proppant stages at the expense of the main zone. In the fracture optimization process, the design typically assumes the creation of a single hydraulic fracture, and fluid and sand volumes are designed to optimize the sizing of this single fracture. If the single fracture assumption is not valid, then the design may not be maximizing the net present value of the treatment. A methodology is needed to identify this situation and modify the design to prevent the loss of reserves.

SITUATION A - SINGLE MAJOR PAY ZONE WITH PERIPHERAL ZONES

In many multiple zone situations a significant portion of the reserves are located in one zone, with secondary zones located in the vicinity of the main zone. In this case a 3-D fracture simulator could be run to determine the final proppant placement if only the main zone is perforated. The 3-D model should be calibrated to an actual design in the area to determine the validity of the input assumptions such as pore pressure distribution, overburden stress, and tectonic component.[10] The model prediction should accurately match actual field results for the zone to be treated. If the calibrated 3-D model prediction of final proppant placement covers the peripheral zones, there is no need to perforate these zones separately. This is often a difficult process to implement if non-engineers (particularly geologists) are involved, as they typically protest loudly if their hard-found pay is not perforated. If this is an insurmountable problem, then a larger treatment is required than a single-wing design would dictate. The optimum treatment based on net present value should be determined, then the pad volume and initial stage volume should be increased proportionately to account for volume lost to the peripheral fractures. A second option is to perforate all of the pay intervals, drop proppant slugs during the pad, shut down, and then pump the main job with the optimized design. The job volume pumped after the proppant slugs should be the optimized design for the main zone. This is somewhat less precise than treating the main zone only, however it is a better option than designing the job for one wing and losing fracture length to the multiple fractures.

SITUATION B - MULTIPLE MAJOR PAY ZONES

This situation is common in many areas, and a possible solution can be based on economics. The productivity of each zone with various completion options should be determined using techniques discussed in Ref. 10. The worst case assumption should be made that one zone will receive only the initial proppant stages and have skin removed, while the other zone will receive the majority of the treatment. If the lost production in either zone from a short fracture treatment is greater than the cost of staging these zones separately, then multiple stages should be implemented. A second method would be to employ advanced multiple zone fracture modeling techniques to predict the actual distribution.[12] While these models often require zone by zone reservoir pressure and frac gradient information to be valid, they address the situation where the minor zone takes more than just the initial pad and proppant stages. The treatment volumes pumped should account for separate multiple fractures in this case and should be significantly larger than the single wing design.

PERFORATION CONSIDERATIONS

If the fracture dip is unknown, a safe rule of thumb to apply is that perforations should be no further than 2 feet apart.[13] This rule of thumb was developed from extensive studies of deviated wellbore completions done on the North Slope of Alaska. Perforation phasing is a current topic of discussion in the industry, with two distinct schools of thought. One approach is to perforate multiple shots per foot (usually 3 or 6) with 60 degree phasing. This pattern would result in perforations on each side of the wellbore within 15 degrees of the maximum principal stress direction. This orientation should result in the minimum breakdown pressure attainable. Studies done with oriented perforating have confirmed this.[14] A potential drawback is the creation of multiple fracture strands around the wellbore all pointing in the direction of the maximum principal stress, with a subsequent loss of fracture width in the main fracture until the strands are bridged off. In addition to the bridging off of multiple fractures seen in Field Example 3, proppant slugs are designed to bridge these secondary fractures as well. A recently developed approach is to perforate with zero degree phasing, with the assumption that the fracture will initiate from the root of the perforation and find the maximum stress plane on both sides of the wellbore.[15] While this option should require a higher breakdown pressure, the potential for multiple strands exiting the wellbore is minimized. In both cases a 20 ft gun length should be adequate to initiate any fracture. If more interval must be perforated, the subsequent interval should be adjacent to the first with the shots no farther than 2 feet apart.

CLUSTER PERFORATING FIELD EXAMPLE

Field Example 6

The well was in the Spraberry Trend in Midland County, an area where four main pay intervals are typically completed in three separate stages. (The Dean, Jo Mill, Driver, and Floyd sands, with the Driver and Floyd combined in one stage). Each stage includes from 200 to 300 feet of interval at one time with 14 to 16 holes with limited entry down casing at 40 to 50 BPM, with the total perforated interval averaging 774 feet. The operator elected to perforate only the top two sands (the Driver and the Floyd) out of four in what is normally one single stage with cluster perforating, and fracture treated the Driver and Floyd zones separately (Fig 10). The median perforated interval in the offset wells was 277 ft in this upper stage alone and 774 feet total, while the cluster well had two stages with 70 and 78 feet of perforated interval. These upper two zones contained 56% of the recoverable reserves in the well, with the remaining 44% from 500 to 1500 feet below these zones. 3-D fracture modeling of the 277 ft perforated interval treatment suggested that even in the best case if a single fracture wing was obtained the proppant settling would be severe with the linear gel system, leaving the Floyd zone partially propped (Fig 11). The two separate treatments were 77 ft apart, and no evidence of communication with the Driver was seen on the Floyd's treatment pressure plot. The two stages were pumped at 30 BPM down 5 1/2" casing using a crosslinked gel system, while all of the offsets were pumped at 50 BPM down 4 1/2" casing using a 30 lb linear system. The bottom stage (Driver) received 30,000 gal of gel and 78,000 lb of sand, while the upper stage (Floyd) received 28,000 gal of gel with 72,000 lb of 20/40. All of the offset wells were treated with an average of 40,000 gal of gel with 110,000 lb of sand in one stage, combining the Driver and the Floyd. In addition, the Dean and Jo Mill are also completed with an additional 160,000 gal of fluid and 322,000 lb of sand. Based on 3-D simulations of the fracture it is unlikely that the Driver or Floyd treatments stimulated the Jo Mill or Dean, thus all of the production from the cluster well should be coming from the Driver and the Floyd.

A comparison with offset production is provided. The comparison suggests that even though the cluster perforated well only opened 56% of the pay completed in offset wells, the production was significantly higher. The cluster perforated well produced 40,798 BO during the first 39 months of production, compared to 28,541 BO for the average of 12 offset wells and 19,591 BO for the closest offset. This was a 43% improvement over the offset average and a 108% improvement over the closest offset. This was significant in light of the cluster having only 143 feet of perforations, compared to the average offset well stimulating 100% of the pay with 774 feet of perforations. Given that the cluster well had average recoverable reserves based on the log analysis, this supports the use of the technique in this area.

CONCLUSIONS

The use of cluster perforating has applications in multiple zone environments. It is an economically viable alternative to limited entry perforating when properly executed. The technique should be integrated with 3-D fracture simulators to estimate the proppant distribution with various treatment options. If there is a single major pay zone present, the main pay should be perforated and the minor zones drained with the propped fracture. If there are multiple major pay zones present, an economic analysis of various completion options for each zone is recommended. This analysis will determine if cluster perforating each zone separately is economically superior to having one zone receive the majority of the treatment and the other having only near wellbore skin removed. If the present value of the productivity from an optimally designed fracture treatment in the minor zone is greater than the cost of staging, then multiple cluster perforated stages are recommended.

REFERENCES

1. Gas Research Institute, "Techniques for Determining Subsurface Stress Direction and Assessing Hydraulic Fracture Azimuth," GRI Topical Report 93-0429, Gas Research Institute, Chicago, Nov. 93.
2. Miller, W.K., et al: "In-Situ Stress Profiling and Prediction of Hydraulic Fracture Azimuth for the West Texas Canyon Sands Formation," SPE paper 21848 presented at the 1991 Rocky Mountain Regional/Low Permeability Reservoirs Symposium, Denver, April 15-17.
3. Gas Research Institute, "Application of Advanced Geological, Petrophysical, and Engineering Technologies to Evaluate and Improve Gas Recovery from Low Permeability Sandstone Reservoirs," Report No. GRI-89/0140, June 1989 pp 64.
4. Fast, R.E. et al:"Description and Analysis of Cored Hydraulic Fractures-Lost Hills Field, Kern County, California," SPE Paper 24853 presented at the 1992 SPE Annual Technical Conference and Exhibition, Oct 4-7, Washington, D.C.
5. Warpinski, N.R., et al:"Examination of a Cored Hydraulic Fracture in a Deep Gas Well," SPE Paper 22876 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, October 6-9.
6. Barba , R.E. and Meyer, B.R.: "Integrating Wireline Data with Three-Dimensional Hydraulic Fracture Simulators in the Spraberry Trend," paper SPE 25509 presented at the 1993 SPE Production Operations Symposium, Oklahoma City March 21-23.
7. Holditch, S.A., Rahim, Z., and Holcomb, D.:"Using Tracers to Evaluate Propped Fracture Width," presented at the 1994 Southwestern Petroleum Short Course, Lubbock, April 20-21.
8. Cleary, M.P., et al: "Major New Developments in Hydraulic Fracturing with Documented Reductions in Job Costs and Increases in Normalized Production," paper SPE 28565 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, La. Sept. 25-28.
9. NSI Technologies, Inc:"Well Completion and Hydraulic Fracture Treatment Design and Analysis of the Canyon Sands (Lower Interval)," GRI topical report 91-0165, Gas Research Institute, Chicago, May 1991.

10. Barba, R.E., Linroth, M.A., and Wooten, C.T.: "Designing Permian Basin Fracture Treatments Using 3-D Fracture Simulators," presented at the 1994 Southwestern Petroleum Short Course, Lubbock, April 20-21.
11. Barba, R.E.:" Improving Production in the Spraberry Trend with Wireline Inputs," presented at the 1987 Southwestern Petroleum Short Course, Lubbock, April 20-21.
12. Elbel, J.L.:"A Method to Estimate Multizone Injection Profiles During Hydraulic Fracturing," paper SPE 21869 presented at the 1991 SPE Rocky Mountain Regional Meeting, April 15-17.
13. Pearson, Mark, personal correspondence.
14. Pearson, C.M., et al: "Results of Stress-Oriented and Aligned Perforating in Fracturing Deviated Wells," SPE paper 22836 presented at the 1991 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 6-9.
15. Stadulis, J.M.:"Using Zero Phased Perforations and Proppant Slugs to Greatly Increase Overall Sand/Fluid Ratios in Formations Prone to Screenout," paper SPE 29549 presented at the 1995 SPE Rocky Mountain Regional/Low Permeability Reservoirs Symposium, Denver, Mar. 19-22.

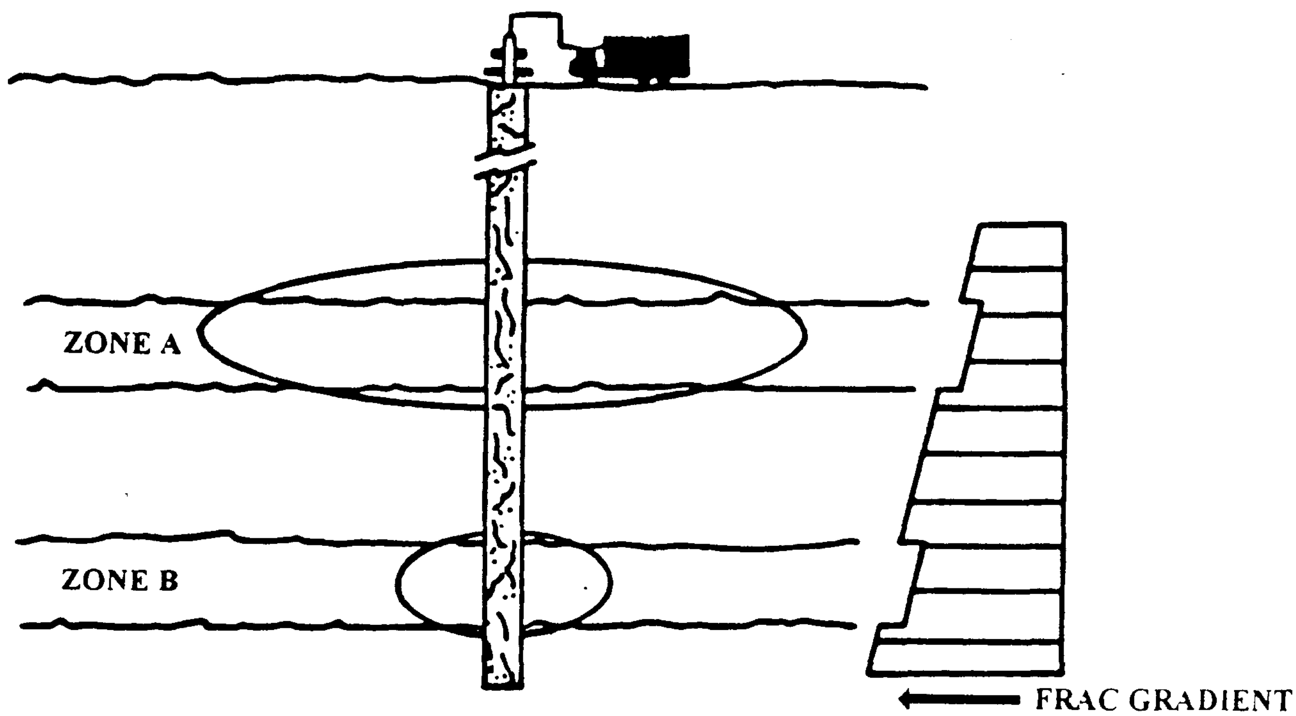

Figure 1

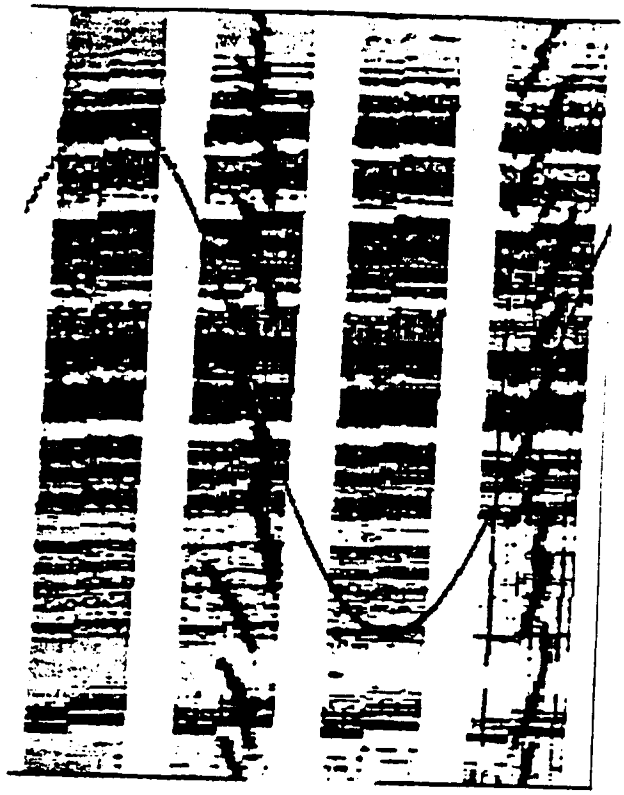

Figure 2

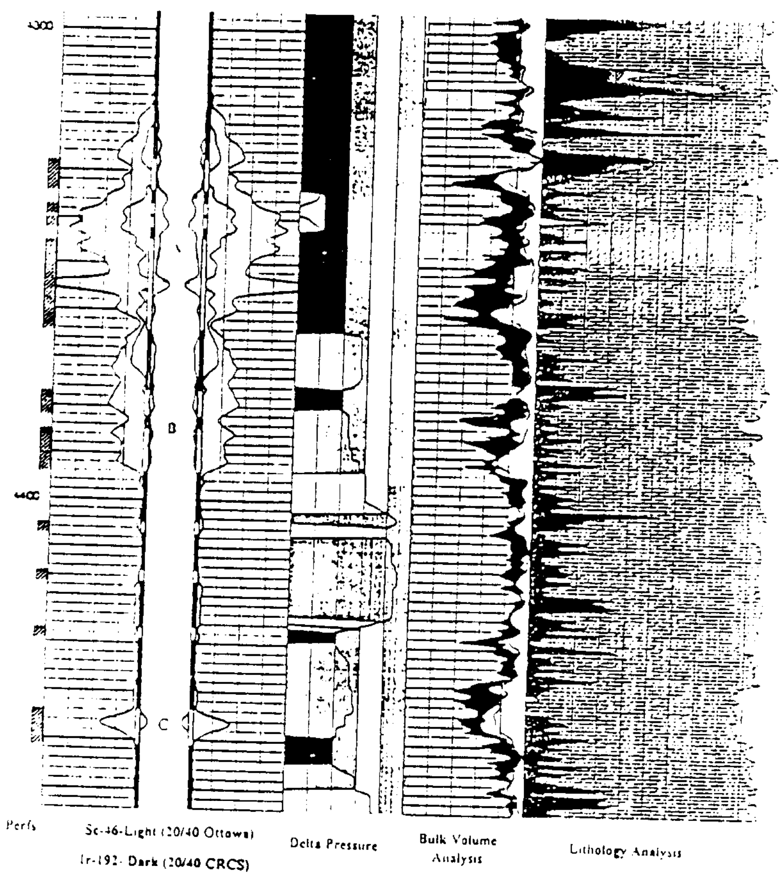

Figure 3

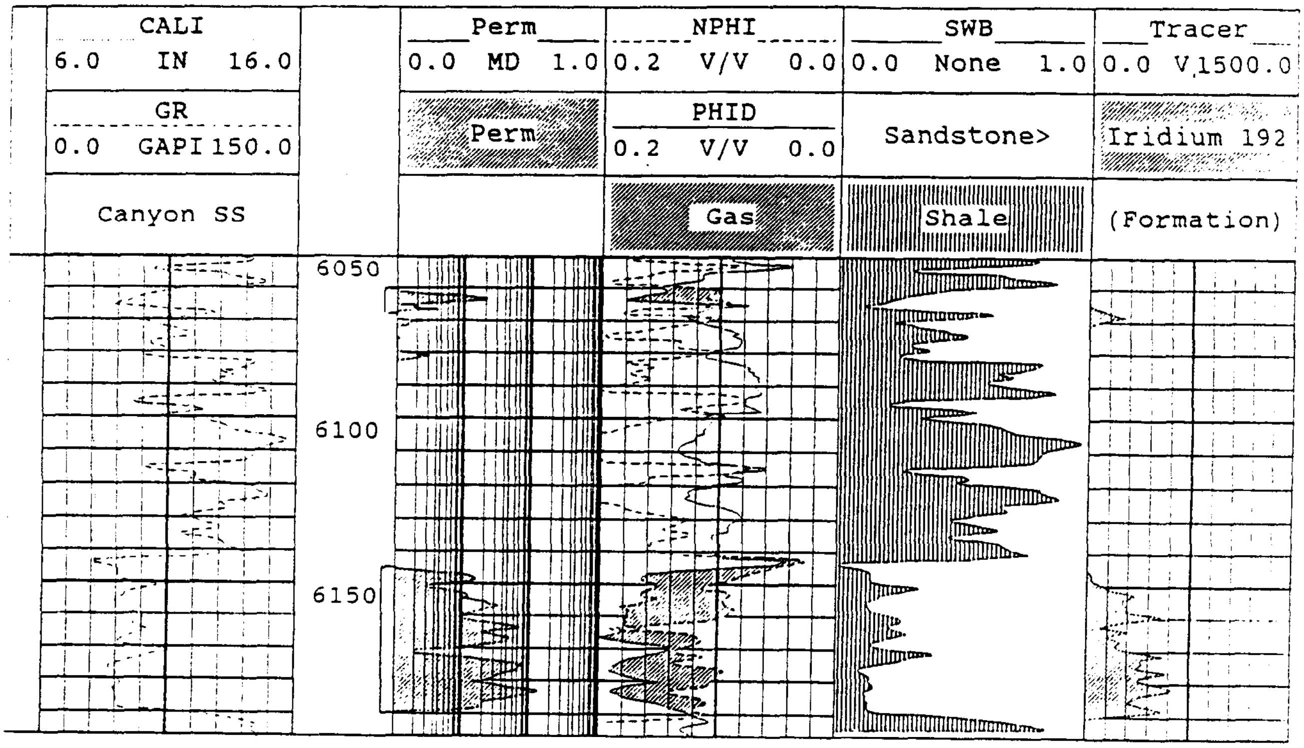

Figure 4

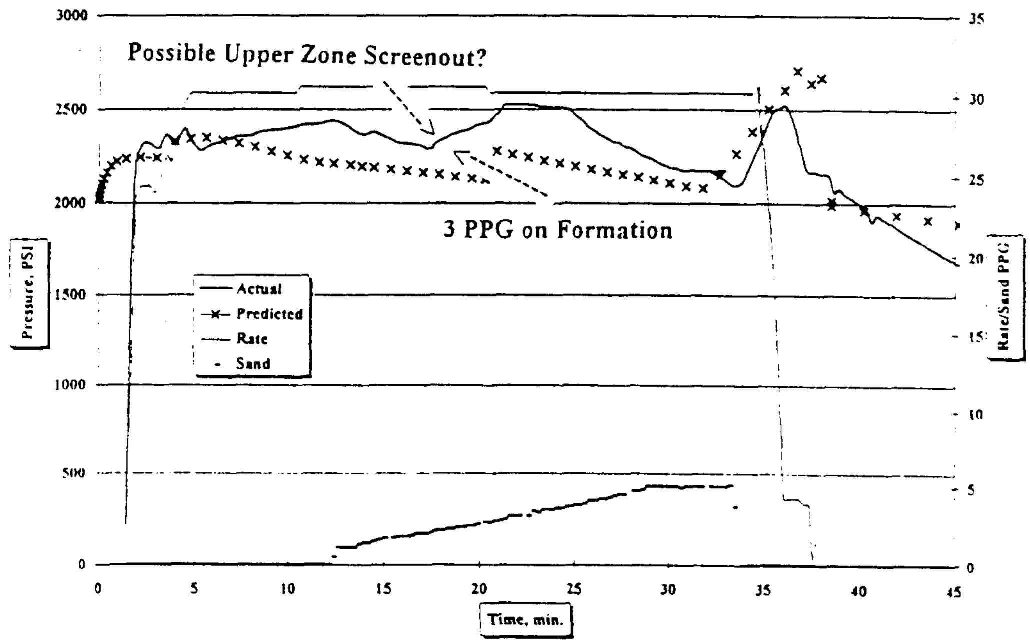

Figure 5 - Field Example 2 Surface Pressure Plot

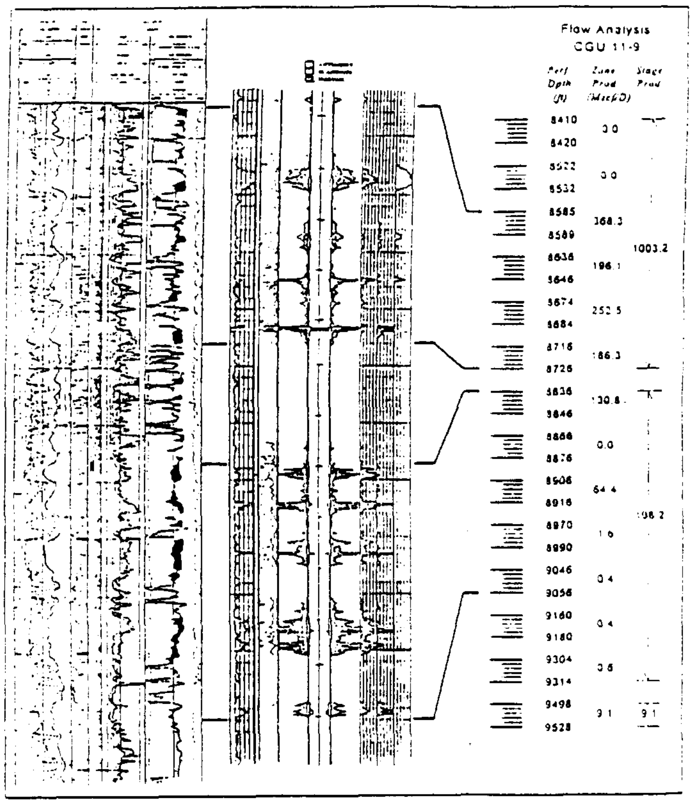

Figure 6

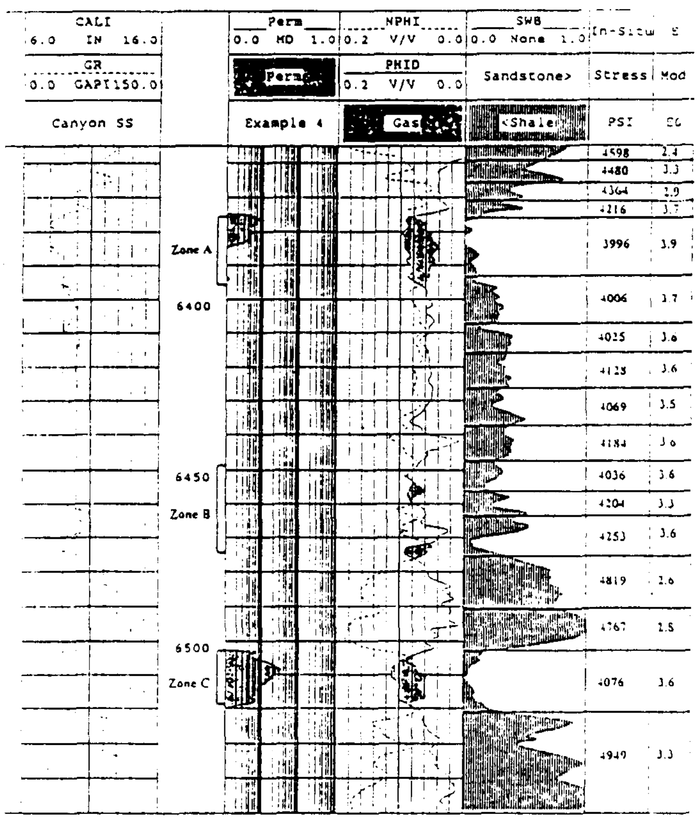

Figure 7

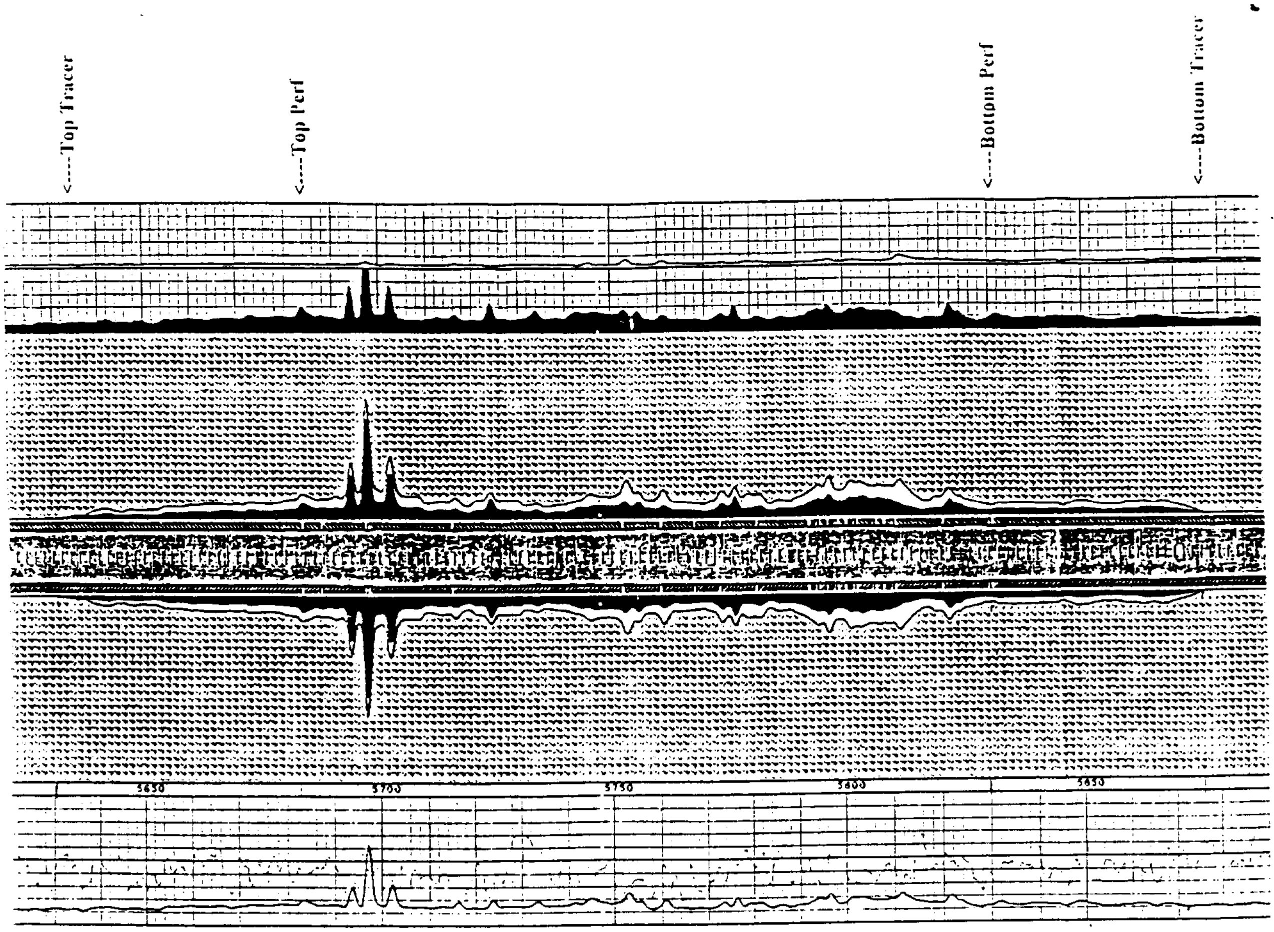

Figure 9

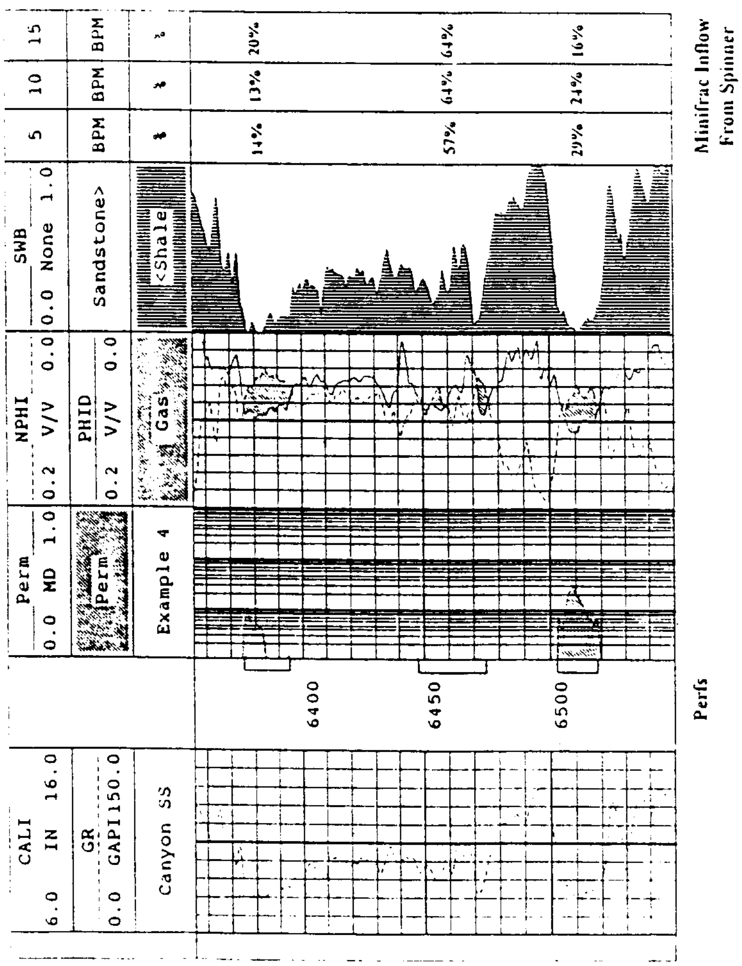

Figure 8

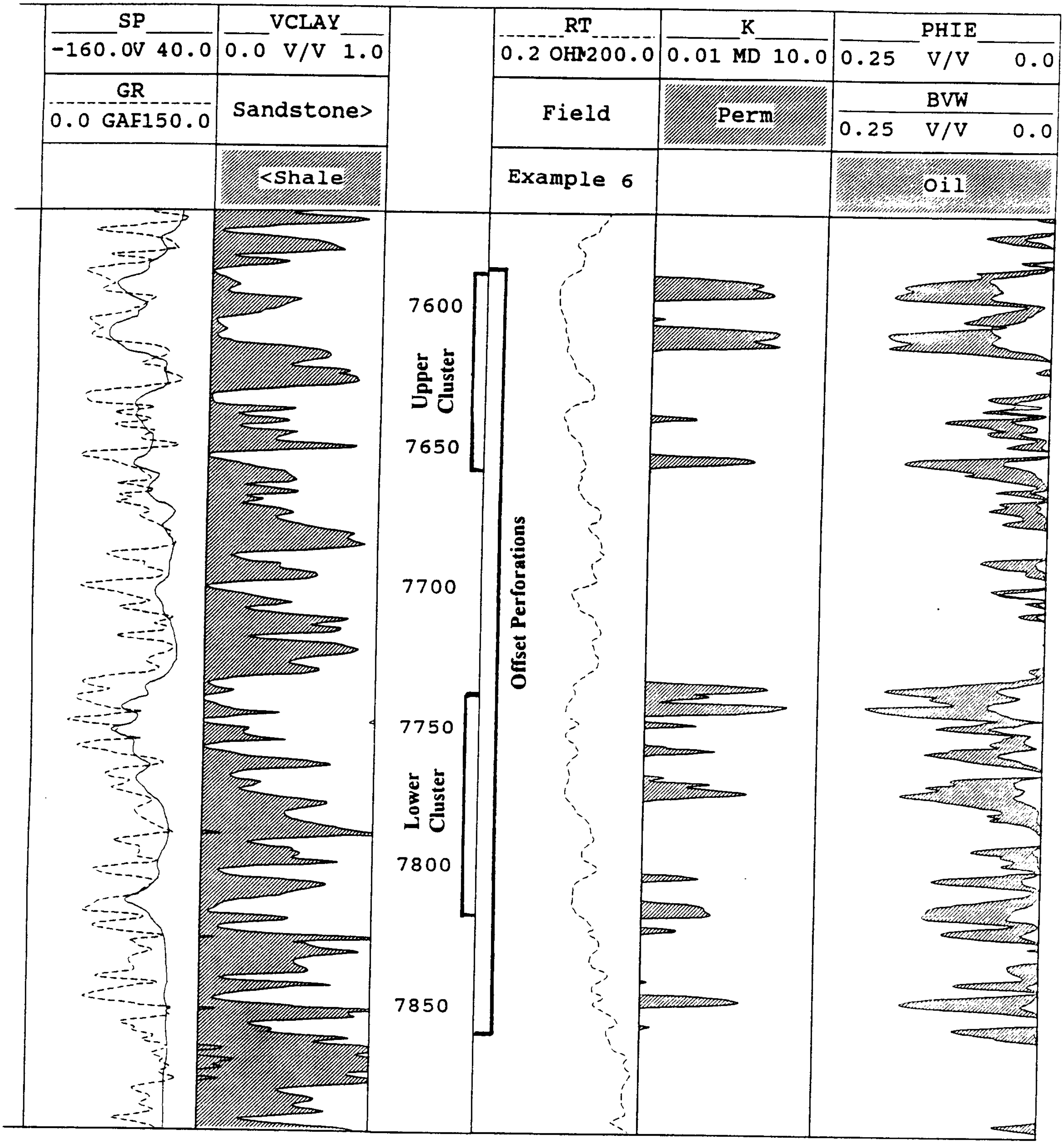
SP
-160.0V 40.0
GR
0.0 GAF150.0
VCLAY
0.0 V/V 1.0
Sandstone>
<Shale
RT
0.2 OHM200.0
Field
Example 6
K
0.01 MD 10.0
Perm
PHIE
0.25 V/V 0.0
BVW
0.25 V/V 0.0
Oil
7600
7650
7700
7750
7800
7850
Upper Cluster
Lower Cluster
Offset Perforations

Figure 10

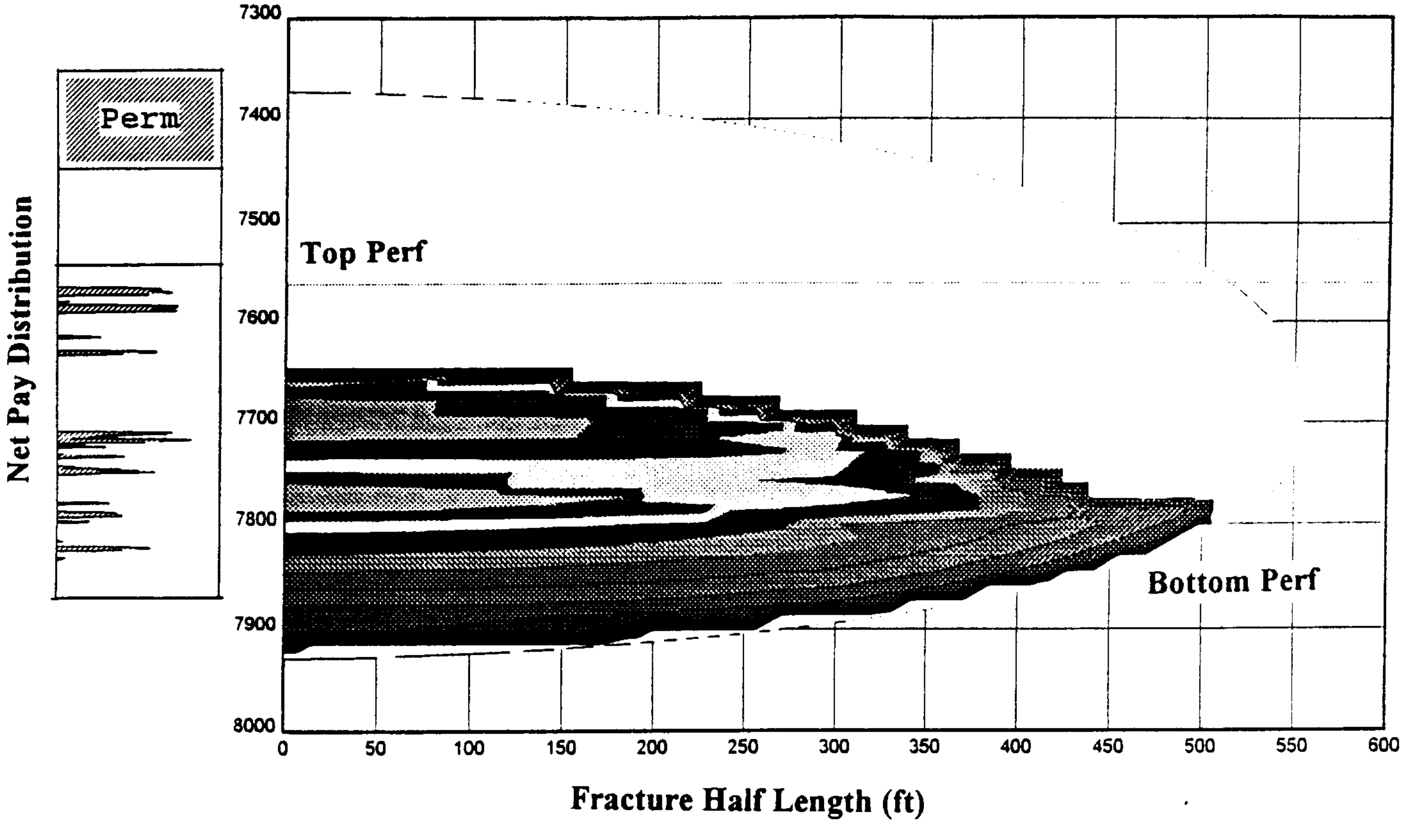

Figure 11 - Field Example 6 Offset Proppant Distribution
(Assuming One Fracture Created with Limited Entry)

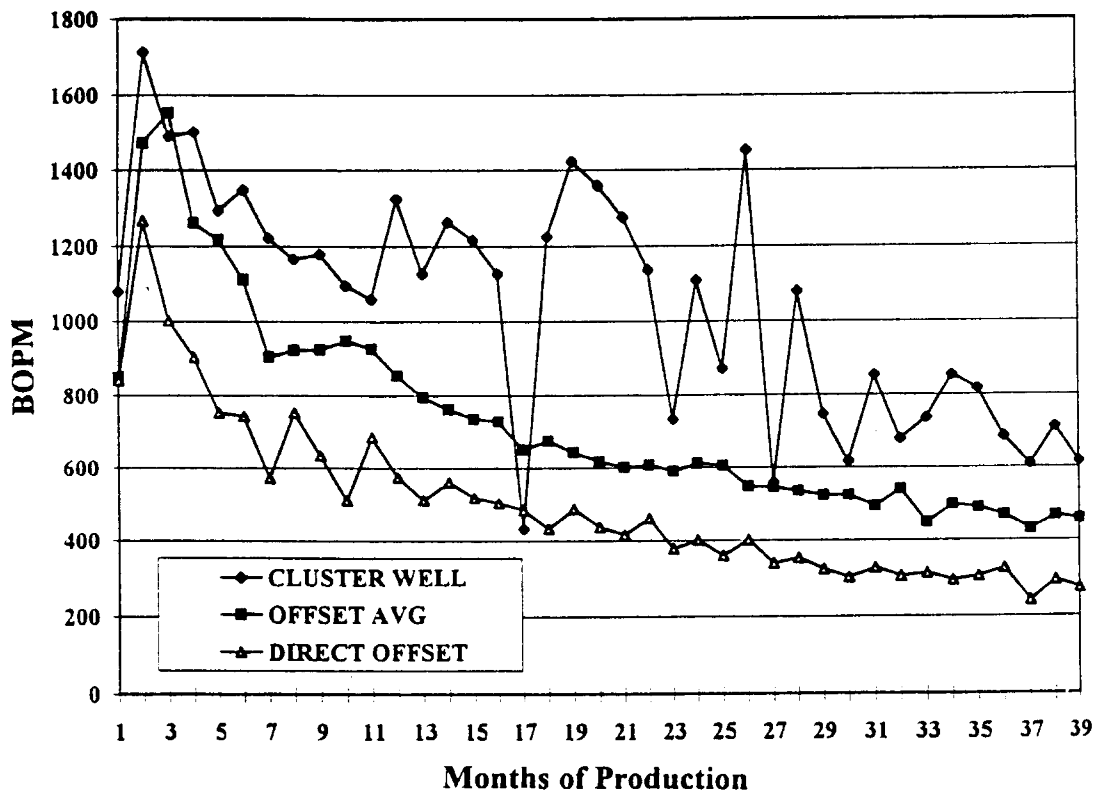

Figure 12 - Field Example 6 Cluster
Well Production vs. Offsets