MULTI-STAGE FRACTURE TREATMENTS: PACKERS AND SLEEVES OR PERFORATIONS, WHY NOT BOTH?

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ABSTRACT

The rapid expansion of horizontal drilling in unconventional gas plays such as shales and tight sandstones has lead to large increases in the number and size of fracturing treatments. Successful fracturing treatments on these wells require multiple stages and proper zonal isolation between the intervals being treated. Zonal isolation and completion techniques typically take the form of either a cemented casing/liner string and stage fracture treated using a perf and plug methodology or a system of packers and sliding sleeves fracture treated in a continuous operation. Each completion technique has its own set of advantages and disadvantages and is typically viewed as mutually exclusive of each other. A case study showing a combination of these techniques being implemented in successful fracturing treatments in central and western Oklahoma will be shown. The application of these combined techniques on future remedial stimulations will also be discussed.

INTRODUCTION

The percentage of new wells being drilled horizontally continues to increase. Since March 2010 horizontal wells accounted for over 50 percent of the North American rig count. As of January 2011 the percentage of new wells being drilled horizontally is over 56 percent. In central and western Oklahoma the majority of these horizontal wells are in unconventional reservoirs namely shales and tight sandstones. These shale and tight sandstone reservoirs require fracture stimulation to be economically successful. To maximize the potential of the well each fracture treatment must be isolated from the adjacent stages to maximize the effectiveness of the fracture treatment and the resulting production. Hydraulic isolation is especially important along the lateral as four to twenty or more fracture treatment stages may be performed.

To achieve zonal isolation between each fracture treatment stage several completion methods have been used. The most common types of completion fall into one of two main categories, a cemented casing string staged with perforations and bridge plugs or an openhole packer system with ball seats and sleeves. Other methods such as mechanically opened and closed sleeves, limited entry techniques and external casing perforating have been used. Several methods of coiled tubing fracturing have also been used including the use of coiled tubing to abrasive jet perforate. An isolation plug on the end of the coil or the setting of a proppant plug via coil provides the zonal isolation.

In the case of cemented casing the hydraulic fractures are propagated from the lateral via perforations that are clustered in regular intervals that are spaced roughly 50 to 150 feet apart per fracturing stage. Each fracture stage is then isolated by setting a bridge plug above the last set of perforations and below the next stage perforations. This process is commonly called the “perf and plug completion”. In cases where slick water or linear gels are used the bridge plug will usually be put in place by being pumped down the lateral on the end of wireline along with perforating guns for the next stage. In cases where crosslinked gels are used concerns of over flushing proppant away from the wellbore may require the use of coiled tubing to place the plug in the lateral without pumping any additional fluids into the zone minimizing the risk of flushing proppant away from the wellbore. Once the plug is set and the next stage is perforated, the next fracture treatment is performed and this process is repeated until the designed number of stages is completed.

In the case where openhole packers are used an un-cemented casing string is ran in the lateral with the mechanical set or swellable packers spaced out to provide the isolation between the fracture treatment stages. Access to the formation is provided not by perforations but by a frac sleeve that is placed in the casing string between the isolation packers. The first stage sleeve is pressure actuated and is opened, usually prior to the actual day of the fracture treatment, by applying a predetermined amount of pressure to the casing string. With the first stage sleeve open the fracture treatment is performed. At the end of the first stage treatment an actuation ball is run to seat in the next stage frac sleeve. Immediately following the ball the next fracture treatment is started. Once the ball reaches the next stage frac sleeve it seats and opens the sleeve by shearing pins at a designed differential pressure providing access the formation between the next set of isolation packers allowing that section to be fracture treated. In addition to opening the sleeve the ball also provides internal wellbore isolation preventing the fracture treatment from entering the previous stage. At the end of the second stage another ball, which is progressively larger than the last is pumped, again isolating the previous stage and opening the next sleeve. This process is repeated until all stages are fracture treated in a continuous operation.

The advantages and disadvantages of each of these systems would be a case study in itself and will not be attempted. Usually one method or the other is chosen as the completion system for the well without overlapping the different technologies. The following two case histories will show how a combination of isolation packers, perforations and bridge plugs can be used together to fracture treat challenging well conditions.

CASE HISTORIES

Example 1.

This horizontal Woodford well in central Oklahoma has 5 ½" casing set at a measured depth (MD) just over 17,450' in an 8 ½" hole. True vertical depth (TVD) averages 12,650' with an average bottom hole static temperature (BHST) of 207°F along the lateral. The casing was cemented in place with 2,135 sacks of a 50:50 Pozzolan:Class H Portland cement blend tailored to provide minimal impairment to the initiation of hydraulic fractures. A bond log run confirmed the top of cement to be at 9,900' which placed cement as designed inside the 9 5/8" intermediate casing which was set at 10,416'.

Subsequent pressure testing of the casing revealed that there were multiple casing collar leaks in the string. This resulted in the original perf and plug completion procedure to be impractical and high risk. To overcome this challenge a combination of different technologies was required. The new completion plan was to remove the top portion of the 5 ½" casing and replace it with a tapered string of 5 ½" casing with a string of 3 ½" tubing on the bottom of it. The 3 ½" portion in the lateral would have cased hole packers and frac sleeves. Prior to running this string all twelve of planned fracture stages in the cemented 5 ½" casing lateral were pre-perforated. The cased hole packers and frac sleeve were spaced to isolate these pre-perforated intervals into the twelve separate frac stages. A total of twelve cased hole packers and seven frac sleeves were run to isolate and treat this well. Figure 1 details the placement of the packers and sleeves. The number of actuation ball sizes available at the time limited the number of frac sleeves to just seven sleeves. Recent advances in this technology have increased the number of ball sizes available and all of these stages could be fractured through sleeves today.

The Woodford wells in this area are typically fracture treated at 80 to 100 barrels per minute (bpm) but that would not be possible with the tapered string containing 3 ½" pipe so a lower rate fracture design had to be made. The design rates to stay within the pressure limits set by the operator were estimated to be 35 bpm on the early stages and as the measured depth decreased the rate would be increased up to 45 bpm. The first seven stages were fracture treated via casing and liner through a frac sleeve into the liner-casing annulus then through the perforations in the 5 ½" casing in the lateral and then into the formation. These first seven frac's would be staged in the normal way for a packer and sleeve system by dropping a ball at the end of the treatment for that stage. The one exception is that no ball was dropped at the end of the seventh stage. Figure 2 is a plot of the treatment data for several of the frac stages. Figure 3 is a more detailed plot of the treatment data during the time the actuation ball seats and opens the next sleeve. Starting with stage eight a composite bridge plug and perforating guns were run in the hole using coiled tubing. The plug was set and the coiled tubing pulled up and the 3 ½" liner was perforated between next set of isolation packers. The location of the perforations in the 3 ½" liner were designed to be on depth with pre-perforated sections of the 5 ½" casing. Each stage consisted of three separate 2' perforated intervals in the 5 ½" casing with a 5' perforated interval in the 3 ½" over the location of the perforations in the 5 ½" casing. The coiled tubing was pulled out of the hole and the next stage was frac'ed. Once that stage was frac'ed another plug was set and the next interval was perforated and fracture treated. This plug and perf methodology was repeated for the remainder of the twelve stages.

Each of the twelve stages had a similar pumping schedule. The treatment would start with a 5,000 gallons 15% Hydrochloric (HCl) Acid spearhead follow by 1,500 gallons of 6:1.5% Hydrochloric:Hydrofluoric (HF) Acid. After the acid stages the main treatment of slick water and proppant were pumped with alternating stages of slick water sweeps and proppant laden fluid. The initial proppant pumped on each stage was 100 mesh White Sand with the main body of the treatment being precured 40/70 mesh resin coated sand. A tail in of premium 40/70 mesh partially cured resin coated sand was used to minimize the potential for proppant flow back. Table 1 is an example of a typical designed treatment schedule. The actual job schedules however were adjusted throughout the treatment as needed based on treating conditions. Table 3 shows a treatment summary of each stage detailing the amount of fluid and total proppant. Fracture initiation was made on all twelve stages and all of the stages were pumped to completion without a screen out. After the fracturing processes were completed coiled tubing was used to drill out all of the composite bridge plugs, balls and frac sleeves.

A proper evaluation of the production response for this treatment would require an in depth study of offset geology, reservoir pressure, lateral length, number of fracture stages, fracture fluid and proppant type and many other variables beyond the scope of this paper. A simple production comparison to offset wells is shown in Figure 4.

Economics must be a consideration in any completion design. The methods used in this example would not be the most economically feasible for a normal completion but for the well condition challenges presented by this well it was a very viable and practical choice.

Example 2.

This western Oklahoma Cleveland Sand well was drilled to just over 13,500’ with an average TVD of 9,660’ and an average BHST of 177°F in the horizontal section. With 7” intermediate casing set at 10,053’ the initial completion plan placed a 4 ½” liner with openhole packers and eleven frac sleeves in the horizontal section back up to a liner top packer at 8,981’. Figure 5 details the wellbore configuration and the placement of the packers and sleeves. The well was to be fracture treated in a continuous operation via the 7” casing and 4 ½” liner with a crosslinked Borate frac fluid with 25-35% Nitrogen added. Actuation balls were to be used to open the frac sleeves and provide isolation to stage the treatments.

The surface treating pressure on stage one was higher than expected and the interval screened out early into the treatment with only 15,400 pounds of ceramic proppant being placed into the zone. The screen out occurred while 2 pound per gallon (ppg) proppant was at the formation leaving the 3 ppg proppant stage in the pipe. The screen out prevented pumping the actuation ball and opening the next frac sleeve without first flowing the well back or performing a cleanout operation with coiled tubing. Based on the characteristics of the well logs it appeared that several of the intervals may exhibit similar fracture treatment responses. Once a ball seats in the frac sleeve a differential pressure is required to shift the sleeve open and in this case that differential pressure was 2,280 pound per square inch (psi). Even if the other intervals did not screen out the higher than expected surface treating pressures plus the additional differential to shift sleeve would require a surface treating pressure in excess of the operator’s maximum pressure limit allowed on the 7” intermediate casing. Based on these unexpected well conditions a new completion plan was required.

The well was cleaned out with coiled tubing and then all frac sleeve seats were drilled out. A composite bridge plug was set above the pressure actuated sleeve and the 4 ½” liner was perforated between the isolation packers of the next stage. The second stage frac was started and high surface treating pressures were again encountered. The fracture schedule was modified and only 0.25 ppg and 0.5 ppg proppant stages were pumped and the well was flushed. The setting of a composite bridge plug and perforating the next stage was again performed via coiled tubing. This interval was then fracture treated and the process was repeated until all the remaining intervals were fracture treated without any screen outs. Table 2 shows a treatment summary of each stage. After the fracturing processes were completed coiled tubing was used to drill out all of the composite bridge plugs.

As with case history example 1 a proper evaluation of the production response for this treatment would require an in extensive study of all the variables beyond the scope of this paper.

The use of composite bridge plugs and perforating between openhole packers was predicated by unexpected well conditions in this example. The success of this methodology led the operator to run the openhole packer system on future wells but without the frac sleeves. This approach kept the advantages of the openhole completion while removing the any issues involving the use of actuation balls and sleeves.

RECOMPLETION CONSIDERATIONS

The increase in horizontal completions and associated fracture treatments has shown to be successful. One concern that will become more important in the future is how does one recomplete or re-fracture these wells at a later date. There have been many case studies showing that re-fracturing old wells can be very successful in many areas. For wells with a cemented casing string across the lateral the methodology used in case history example 1 can be the answer. An old well with exiting perforations can have a packer and sleeve system put in place isolating the original perforations into fracture stages. In addition to re-fracturing the existing perforations new perforations could be added, isolated and fracture stimulated as well in a continuous operation.

SUMMARY AND CONCLUSIONS

Zonal isolation and completion techniques do not have to be one common completion methodology only. A combination of the different types of completion systems can be used together to successfully fracture stimulate horizontal wells. Two case histories have shown that this is especially true in the case of wells with unexpected challenges where the advantages of the various systems can be combined to remove some of the disadvantages of a single system or methodology. In addition to new well completions a method of re-fracturing old well is also possible by combining the various completion methods.

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Table 1
Case History #1 Treatment Summary

EXAMPLE #1 FRACTURE TREATMENT SUMMARY					
Stage Number	**Depth Feet**	**Fluid Volume Barrels**	**Proppant Volume Pounds**	**Average Rate BPM**	**Average STP PSI**
1	17,133	8,100	44,100	34	9,850
2	16,764	8,460	88,500	35	9,400
3	16,407	9,160	97,500	37	9,300
4	16,046	9,967	113,200	38	8,900
5	15,690	9,975	106,000	39	9,050
6	15,333	10,150	119,000	39	8,970
7	14,972	10,320	121,800	43	9,020
8	14,615	10,252	129,600	45	9,280
9	14,261	10,102	117,500	43	9,280
10	13,904	10,124	127,500	40	9,050
11	13,550	10,238	128,800	44	9,215
12	13,201	11,636	149,200	45	8,550
Well Totals		118,484	1,342,700		

Table 2
Case History #2 Treatment Summary

EXAMPLE #2 FRACTURE TREATMENT SUMMARY					
Stage Number	**Depth Feet**	**Fluid Volume Barrels**	**Proppant Volume Pounds**	**Average Rate BPM**	**Average STP PSI**
1	13,373	1,151	15400*	40	6,515
2	13,039	1,590	11,000	35	6,330
3	12,679	2,823	50,000	33	3,325
4	12,345	1,595	75,000	34	4,560
5	12,012	1,643	75,500	34	4,210
6	11,680	1,629	75,040	35	4,515
7	11,346	2,543	75,940	44	5,185
8	11,057	1,721	75,540	45	4,355
9	10,768	1,590	77,780	44	4,040
10	10,479	1,544	83,330	45	4,734
11	10,189	1,641	75,620	45	3,864
Well Totals		19,470	690,150	45	8,550
			*Amount in formation before well screened out		

Table 3
Case History #1 Treatment Schedule

stage	Fluid Type	Fluid Volume (gal)	Proppant Conc. (ppa)	Proppant Type	Proppant Stage (lbs)	Proppant Cum (lbs)
1	15% HCl Acid	5000				
2	6:1.5% HCl:HF Acid	1500				
3	Slick Treated Water	50000				
4	Slick Treated Water	18000	0.05	100%Sand, White, 100 m	900	900
5	Slick Treated Water	18000	0.10	100%Sand, White, 100 m	1800	2700
6	Slick Treated Water	11000	0.15	100%Sand, White, 100 m	1650	4350
7	Slick Treated Water	8400				4350
8	Slick Treated Water	12000	0.20	100%Sand, White, 100 m	2400	6750
9	Slick Treated Water	8400				6750
10	Slick Treated Water	12000	0.30	100%Sand, White, 100 m	3600	10350
11	Slick Treated Water	8400				10350
12	Slick Treated Water	12000	0.40	100%Tempered LC, 40/70	4800	15150
13	Slick Treated Water	8400				15150
14	Slick Treated Water	12000	0.50	100%Tempered LC, 40/70	6000	21150
15	Slick Treated Water	8400				21150
16	Slick Treated Water	12000	0.50	100%Tempered LC, 40/70	6000	27150
17	Slick Treated Water	8400				27150
18	Slick Treated Water	12000	0.50	100%Tempered LC, 40/70	6000	33150
19	Slick Treated Water	8400				33150
20	Slick Treated Water	12000	0.60	100%Tempered LC, 40/70	7200	40350
21	Slick Treated Water	8400				40350
22	Slick Treated Water	10000	0.70	100%Tempered LC, 40/70	7000	47350
23	Slick Treated Water	8400				47350
24	Slick Treated Water	10000	0.80	100%Tempered LC, 40/70	8000	55350
25	Slick Treated Water	8400				55350
26	Slick Treated Water	10000	0.90	100%Tempered LC, 40/70	9000	64350
27	Slick Treated Water	8400				64350
28	Slick Treated Water	9000	1.00	100%Tempered LC, 40/70	9000	73350
29	Slick Treated Water	6000	1.25	100%Optiprop G2, 40/70	7500	80850
30	Slick Treated Water	3000	1.50	100%Optiprop G2, 40/70	4500	85350
31	Slick Treated Water	2000		Sweep		85350
32	Slick Treated Water	8400		Flush		85350
Total		338300				85350

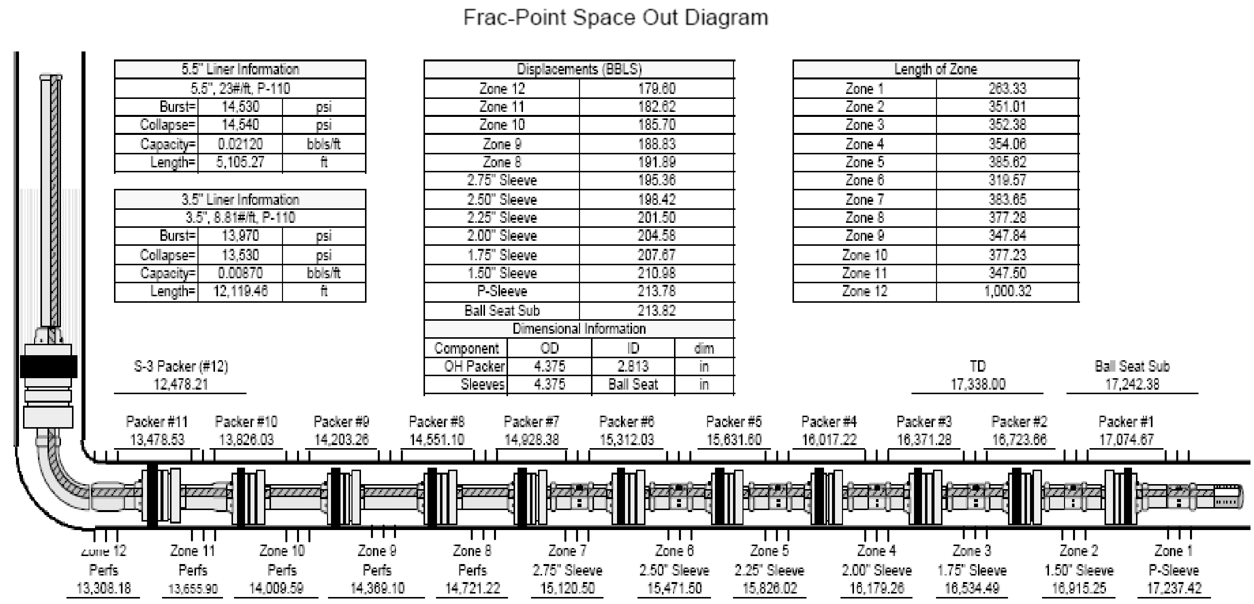

Figure 1 - Case History #1 Wellbore Diagram

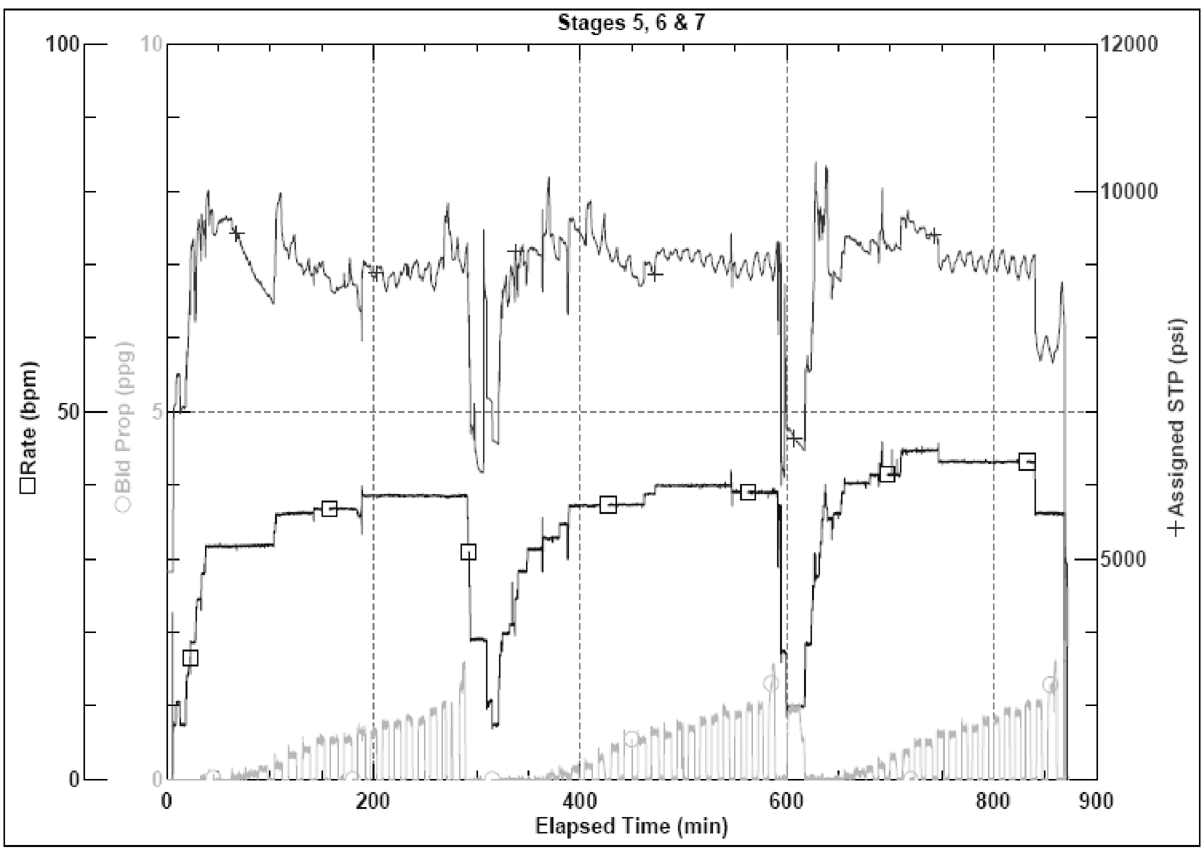

Figure 2 - Case History #1 Fracture Treatment Chart

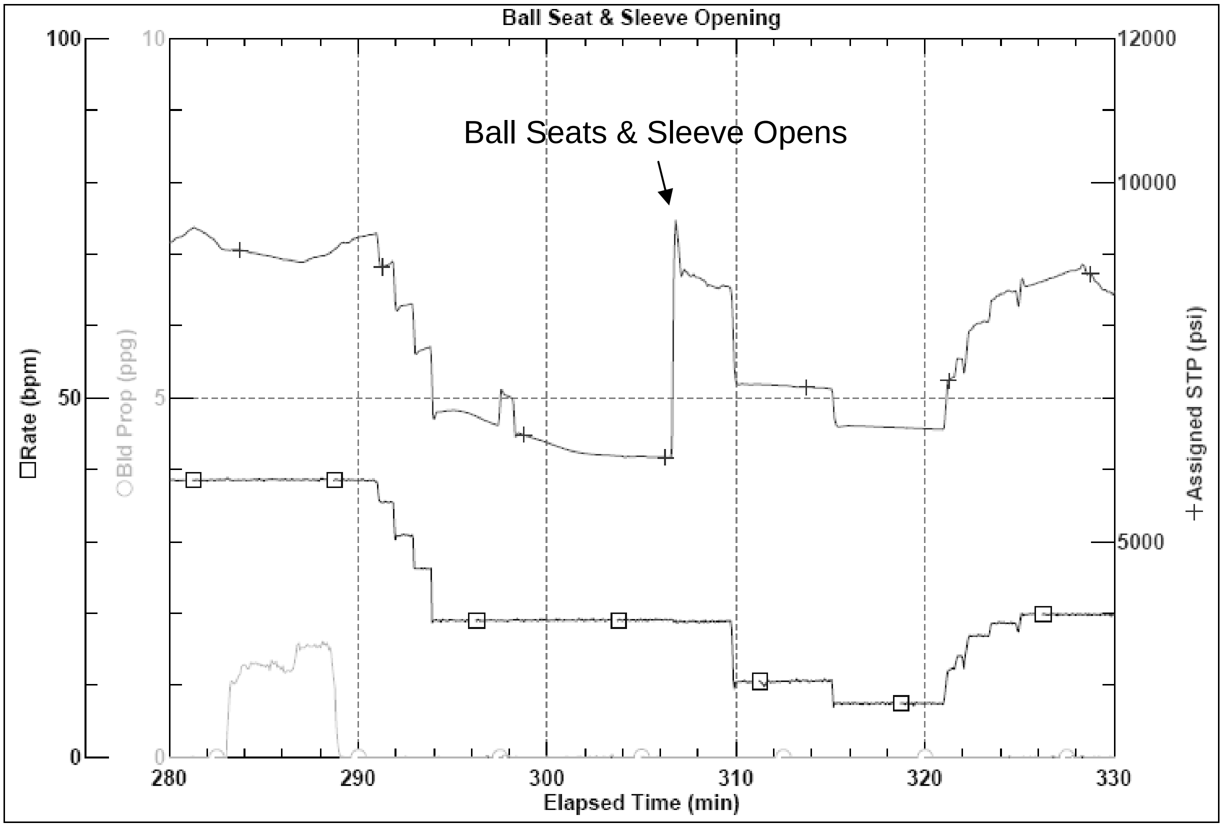

Figure 3 - Case History #1 Fracture Treatment Ball Seat & Sleeve Opening

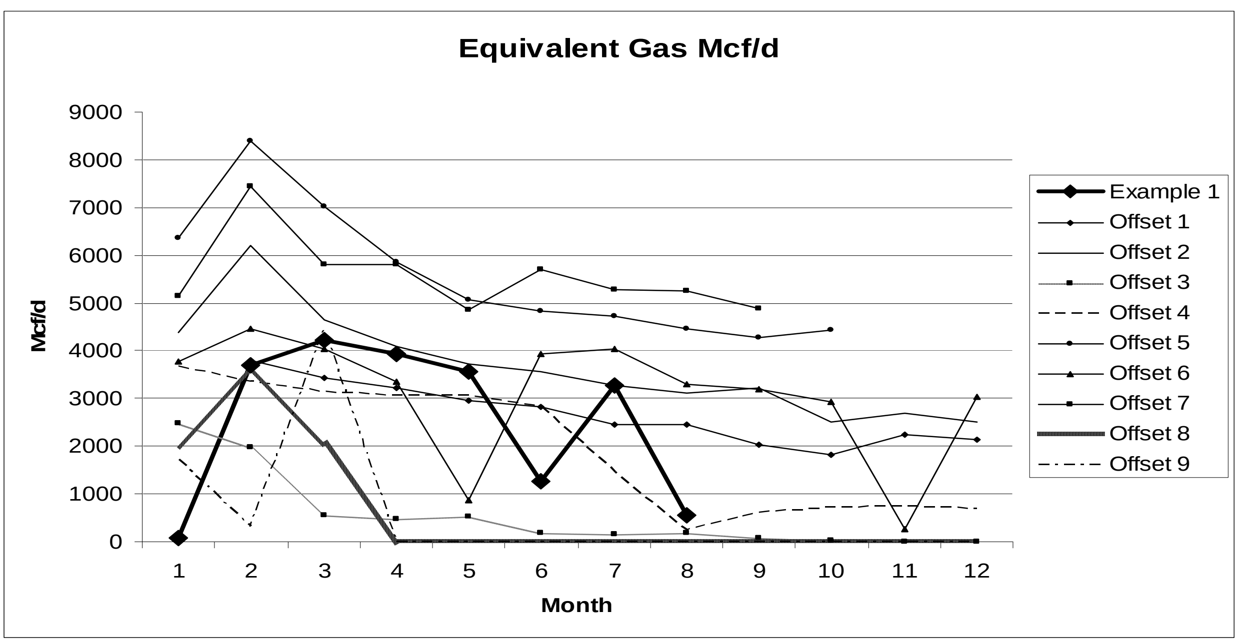

Figure 4 - Case Study #1 Offset Production

Frac-Point Space Out Diagram

Casing Information		
7" 26# P-110		
Burst=	9,960	psi
Collapse=	6,230	psi
Capacity=	0.03826	bbls/ft

Liner Information		
4 1/2" 11.6# P-110		
Burst=	10,690	psi
Collapse=	7,580	psi
Capacity=	0.01554	bbls/ft

Displacements (BBLS)	
Liner Top	343.60
3.500" Sleeve	362.78
3.375" Sleeve	367.28
3.250" Sleeve	371.78
3.125" Sleeve	376.27
3.000" Sleeve	380.77
2.875" Sleeve	385.95
2.750" Sleeve	391.11
2.500" Sleeve	396.29
2.250" Sleeve	401.48
2.000" Sleeve	406.67
P-Sleeve	411.86

Length of Zone	
Zone 1	346.01
Zone 2	333.97
Zone 3	333.82
Zone 4	333.73
Zone 5	332.45
Zone 6	333.03
Zone 7	289.37
Zone 8	288.92
Zone 9	289.42
Zone 10	289.49
Zone 11	290.59

Component	OD	ID	dim
Liner Top Pkr	5.875	3.900	in
OH Packer	5.820	3.875	in
Sleeves	5.750	Ball Seat	in

NOTE: SLEEVE SIZE REFERS TO BALL OD TO SHIFT OPEN

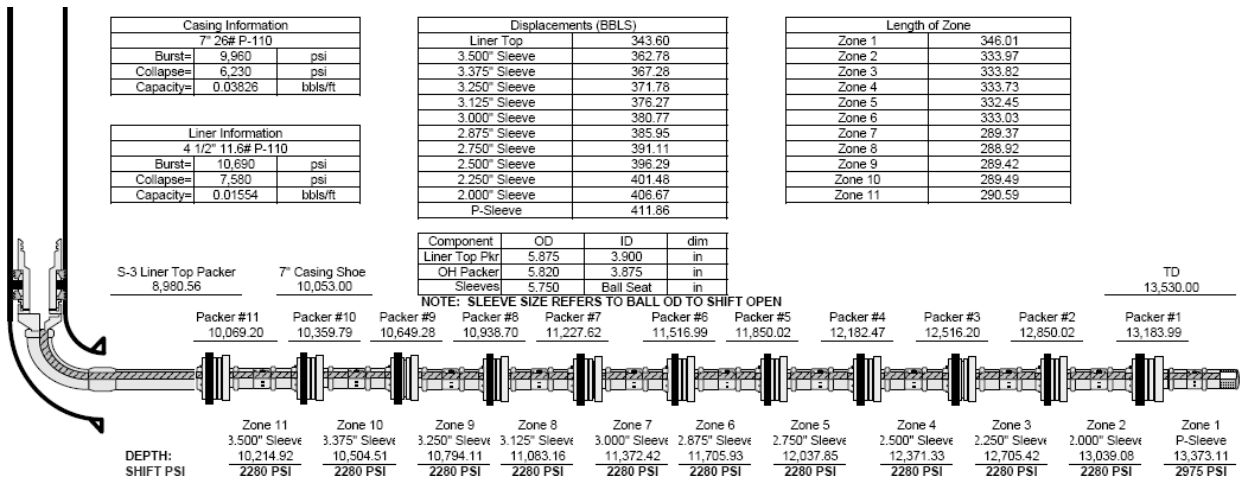

Figure 5 - Case Study #2 Wellbore Diagram