FRACTURE TREATMENT COSTS AND POLYMER DAMAGE REDUCED IN A NOVEL MULTI-STAGE TREATMENT APPROACH

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ABSTRACT

Multi-stage proppant fracture treatments are routinely applied to stimulate discrete formations and, more recently, distinct sections (stringers) within a formation to maximize the production of these finite zones. One method consists of perforating a zone, pumping a crosslinked pad, proppant-laden fluid, and acid followed by a gelled flush. A subsequent stage is then perforated, isolated and the process repeated.

Multi-stage fracture treatments have been optimized by the use of highly efficient perforating techniques that perforate and isolate zones in less than 30 minutes. Further, a novel approach has been implemented that minimizes the total treatment volume by approximately 220 bbls per stage where six to eight stages are common.

This paper will describe the perforating technique, the approach that reduces the treatment volume and will quantify the cost reduction associated with the reduced volumes from actual treatments. Benefits such as the reduction of polymer damage will also be discussed.

INTRODUCTION

Many formations are completed in more than one section or stringer of formation. Open-hole logs may indicate many stringers as promising productive zones and can number as many as ten or more. These zones may cover several hundred feet of pay. The operator must consider many factors to optimize the stimulation of these zones. These include the desired gross and net height of the pay zone, the number of stringers in zone, the distance separating the stringers, the possibility of grouping stringers, the potential productivity of each stringer, and the optimum perforation placement for stimulation. Proppant fracturing each individual stringer can be expensive and time-consuming. Cumulative costs including rig time, specialized downhole equipment, perforating, fracture treatments, and labor costs must be considered.

Multiple stringers are often fractured in clusters of adjacent stringers referred to as “stages”. These groups are collectively perforated and stimulated in the hope that each will be exposed to some of the fracture treatment[1]. Often many perforations[2] are treated in two, three, or four stages sometimes covering 10 or more productive stringers. Stage treatments are frequently pumped down the casing and include such methods as “bridge-plug and packer[3,4], “frac plug and ball”, “ball sealer[5]” and others.

Another stage treatment option is to limit the number of perforations traversing the stringers to limit fluid entry into each perforation and help provide a more even distribution of the treatment fluid into each stringer within a group. "Limited entry"[2,4] can be an effective method to obtain better zonal coverage, but is often subject to uncertainty associated with perforation size and restriction, and formation heterogeneity.

A disadvantage to these types of "stage” treatments is that each stringer may not be stimulated to its maximum productive potential (Fig. 1, 2, 3). Another disadvantage is that often the treatment can take longer to complete than anticipated, thus increasing the costs. Common delays include incorrectly spotting acid across the next zone, screening out a lower zone, and difficulties with downhole equipment (i.e., perforating tools, isolation mechanisms etc.).

EXTERNAL CASING PERFORATING (ECP) REDUCES TIME AND COSTS

An innovative process has been developed and implemented that significantly reduces the time necessary to perforate between stages and helps eliminate costly job delays. The process referred to as external casing perforating or ECP[6], uses perforating mechanisms made-up on the casing as it is being lowered into the hole. A stainless steel, high-pressure tubing control line links each perforating gun mechanism on the external side of the casing and is run to the surface. Once the casing has been positioned properly, the cement job is performed, permanently cementing the casing, gun mechanisms and control line into place. Prior to the stimulation treatment, pressure is placed on the control line to selectively detonate the perforating mechanisms. The gun mechanism placed in the lowermost zone discharges at a lower pressure than does the gun above, and each successive gun above it discharges at a successively higher pressure (Fig. 4). Monitoring the pressure on the casing during perforating verifies that the zone was perforated. Once the perforation module detonates, a flapper valve is actuated to isolate previously treated zones from pressure above the valve. Up to 27 zones have been successfully treated in a single well-bore utilizing this method, averaging nine zones per day. As many as 17 zones have been treated in a single 24-hour period.

Seven multi-stage wells were recently treated. Each consisted of six to seven fracture treatment stages performed in a 24-hour period. Previous treatments using a bridge-plug and packer method took an average of 2.8 days to perform. The cost reduction for each well associated with ECP included a total of $34,200 for 1.9 days of location costs (rig time, perforators, labor etc.) and $28,500 for 1.9 additional days of fracturing equipment and associated costs. A conventional wireline-conveyed bridge-plug and gun approach can often take as long as four hours per zone, and only four stages can normally be completed in one day. In contrast, the time between stages utilizing ECP can be reduced to as little as 15 minutes.

Additionally an average reduction of $3,000 in hydraulic horsepower for each well was realized, as average pump rates per zone were lower than conventional treatments. Other reduced costs can include the elimination of job delays due to perforating and placing isolation equipment, reduced treatment volume, and elapsed time to production (Table 1).

DEAD STRING REDUCES COST~~S~~

A tubing (dead) string has also been effectively used to reduce the treatment time and cost of "stage" fracture treatments. Tubing is suspended in the casing and the fracture treatment is pumped down the annulus. The tubing is used to monitor actual bottom hole pressures during the treatments to anticipate screen-outs and aid in more accurately modeling fracture geometry. In case of a screen-out the dead string can also be used to immediately reverse-circulate proppant out of the wellbore and allow the job to continue with the next stage. (Most conventional stage treatments are performed without a dead string. A screen-out can delay the treatments since tubing must be run in the hole or a coiled tubing unit must be ordered and rigged up to clean proppant out of the hole.) The dead string can also be used to circulate other fluids such as acid in or out of the wellbore.

CROSSLINK MODIFIER REDUCES COST AND FORMATION POLYMER DAMAGE

Individual stage treatment volumes necessarily include flush to displace the proppant-laden fracture fluid from the casing and to spot acid for the ensuing stage. These flush volumes can be significant depending on the casing size, depth and the number of stages to be treated. The flush fluid is normally fresh water or 2% KCl containing surfactants and often 30-to-40 pounds per thousand-gallon concentrations of polymer (normally of the same type used in the main fracture fluid). The flush of the previous stage is displaced into the formation of the ensuing stage in its treatment.

If the flush of a previous stage could be used as part of the fracture treatment for each ensuing stage, then the total treatment volume could be reduced along with treatment cost. More precisely, each flush volume would be crosslinked and used as part of the pad for each of the next stages. If the pad was crosslinked and allowed to remain static for 30 minutes to perforate, the fluid friction encountered in resuming pumping could be substantial enough to appreciably limit fracture pump rates. In a recent treatment, a pump rate of 25 barrels per minute (bpm) through 5.5-inch casing was established during the pad. The treatment was then shut down for 30 minutes. When the treatment was resumed, a pump rate of 0.25 bpm was attained at the same treating pressure. This infers that to use the flush as part of the pad of the ensuing stage's treatment, the flush's crosslink time must be delayed for 30 minutes (or the time to detonate the ECP and resume pumping) to minimize friction pressure and establish fracture pump rates for the next zone. This is beyond the scope of conventional crosslink time-modifiers that delay crosslink times through 50-to-75% of the tubular residence time, i.e. two or three minutes.

In the seven multi-stage wells previously described, each used external casing perforating and four used the extended crosslink time modifier. The modifier delayed the crosslink time of the fluid for the 30 minutes needed for perforating and enabled each flush to be used as part of each ensuing stage at fracture pump rates. The total average treatment was 332,000 gallons of a crosslinked borate fluid. The total treatment volume of each of the four wells was reduced by an average of 221 barrels per stage or 1,381 barrels of fluid. The total cost was reduced an average of $24,706 per well and included 1,381 barrels of water, polymer, surfactants, biocide and two frac tank rentals (Table 1).

A significant benefit of this process is that by reducing the total treatment fluid volume, the potentially damaging polymer pumped into the formation is proportionately reduced. In the above wells, the total treatment volume for each well was reduced by 1,381 barrels containing 30 pounds per thousand gallons guar polymer. This reduced the polymer pumped into the formation by 1,740 pounds. By reducing the amount of polymer placed in the formation the damage to the formation associated with polymer filter-cake deposition and proppant-pack residue is proportionately diminished. Polymer damage[7, 8] has long been associated with hydraulic fracturing to stimulate oil and gas reservoirs. This damage[9] is primarily due to the pressure differential between the hydraulically induced fracture and permeable formation face. Most fracture treatments will experience some leak-off and filter cake deposition. The reduction of polymer damage is viewed as critical to optimal reserve recovery[10].

REDUCED TIME TO SALES

An additional benefit to external casing perforating is the reduction of the completion process time needed for the well to be placed on production after the treatment. In the wells described, the completion time for each well has been reduced to an average of 21.6 hours from 2.63 weeks (18.4 days) for the conventional bridge-plug and packer method previously used by the operator. 17.5 days of earlier production accounted for an average of $70,000 ($4.00/mcf @1,000 mcf/day) for each well. In addition, early and sustained flowback of the wells is considered beneficial to optimal reserve recovery and is a benefit of the ECP process. Studies have indicated that damage to the productivity of formations can be related to the shut-in period of a well after the treatment[11].

Several factors contributed to the reduced completion time, and include flowing the well back immediately after the treatments to make use of the induced hydraulic energy, flowing through the ECP isolation flapper valves and the reduced volume of fluid to recover (due to the reduced treatment volume). Additional reduced costs include the cost associated with the recovery of the 1,381 bbls of fluid per well not pumped, in equipment, labor, rig time, disposal and other associated recovery costs (Table 1).

NET PROCESS COST

In the cases described, the average cost of the treatments, inclusive of the external casing perforating, represents a net cost reduction of $27,906 for each well as compared to conventional bridge-plug and packer methods with similar volumes. The net cost reduction does not include 17.5 days of earlier production or $70,000 per well nor the costs associated with the recovery of 1,381 bbls of fluid not pumped.

SUMMARY

In seven multi-stage wells recently treated, the use of external casing perforating (ECP) reduced perforating time and treatment costs by allowing the treatment of six to seven discrete productive stringers in a 24-hour period. The cost reduction for each well averaged $34,200 for two additional days of location costs (rig time, perforators, labor, etc.) and $30,000 for two days of fracturing equipment. The use of a tubing dead string helped reduce treatment time and costs by providing a method to monitor actual bottom hole pressures, aid in predicting screen-outs, and in the event of a screen-out, the capability of reversing the wellbore clean and resuming the treatment. The use of an extended crosslink time modifier reduced treatment volumes by 1,381 barrels and saved $24,706 per well by allowing the flush of a previous stage to be used as the pad for each ensuing stage in its treatment. Formation polymer damage was reduced due to the reduced treatment volume. $70,000 per well in earlier production was also realized by reducing the completion time from treatment to sales by 17.5 days by means of the reduced fluid volume, and immediate and sustained flow-back through the isolation valves afforded by the ECP**.** Importantly, the process included the selective fracture treatment of six to seven productive zones (stringers) whereas four stages were normally performed with conventional bridge-plug and packer. The process was more efficient, required less time, and was cost-competitive when compared to the conventional bridge-plug and packer method previously used by the operator.

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SI Metric Conversion Factors

(Gal) (3.785412)	(E^{-3})= Liters
(lbm) (4.535924)	(E^{-1})= kg

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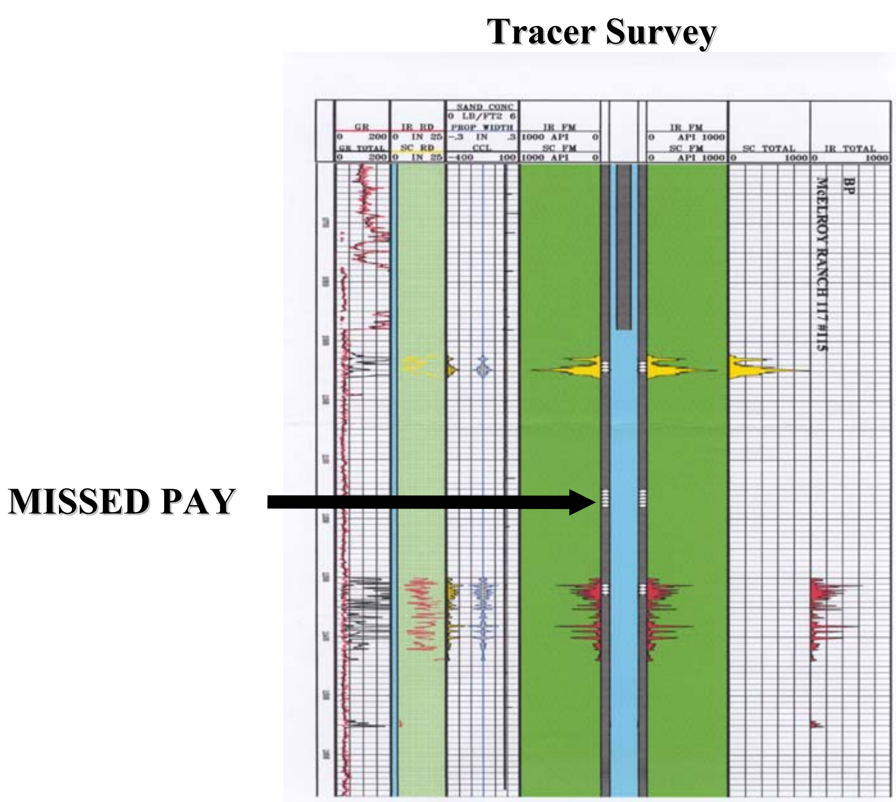


Figure 1 - Two Stage Limited Entry

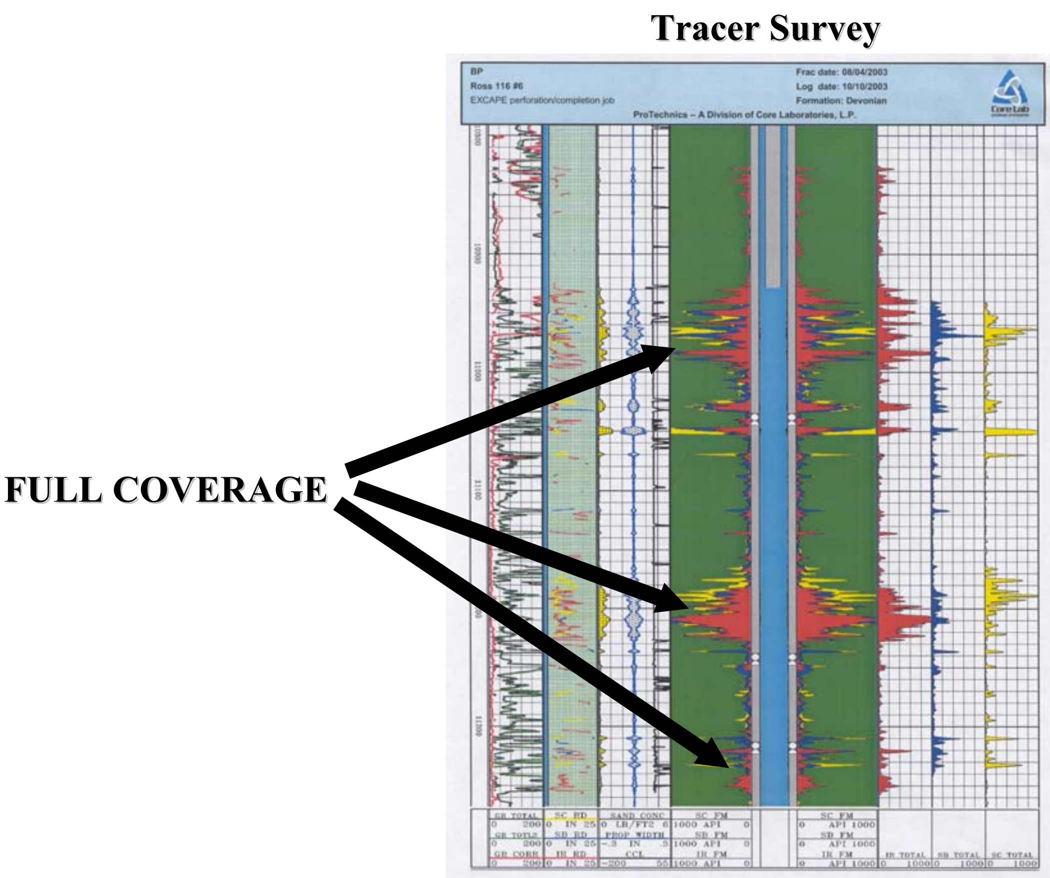


Figure 2- External Casing Perforating

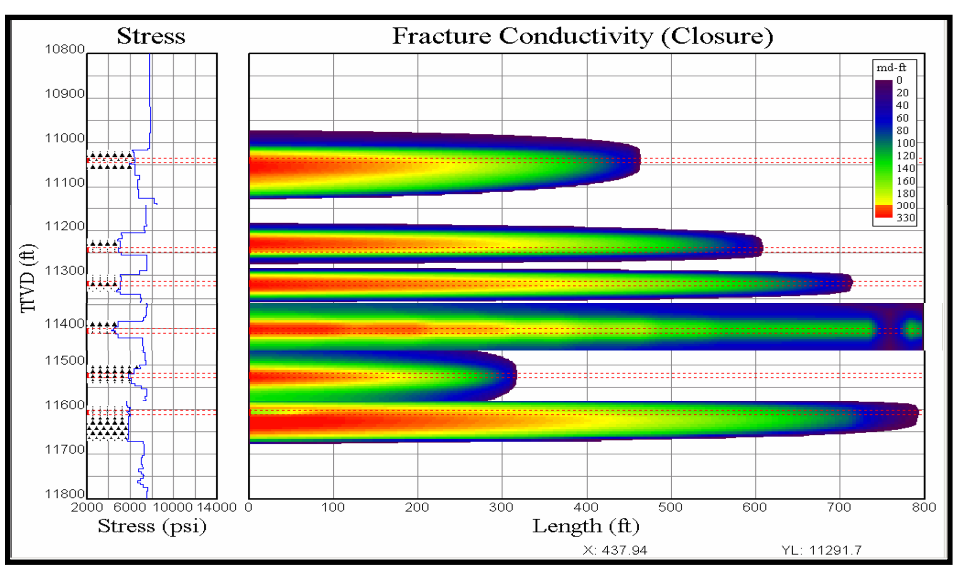
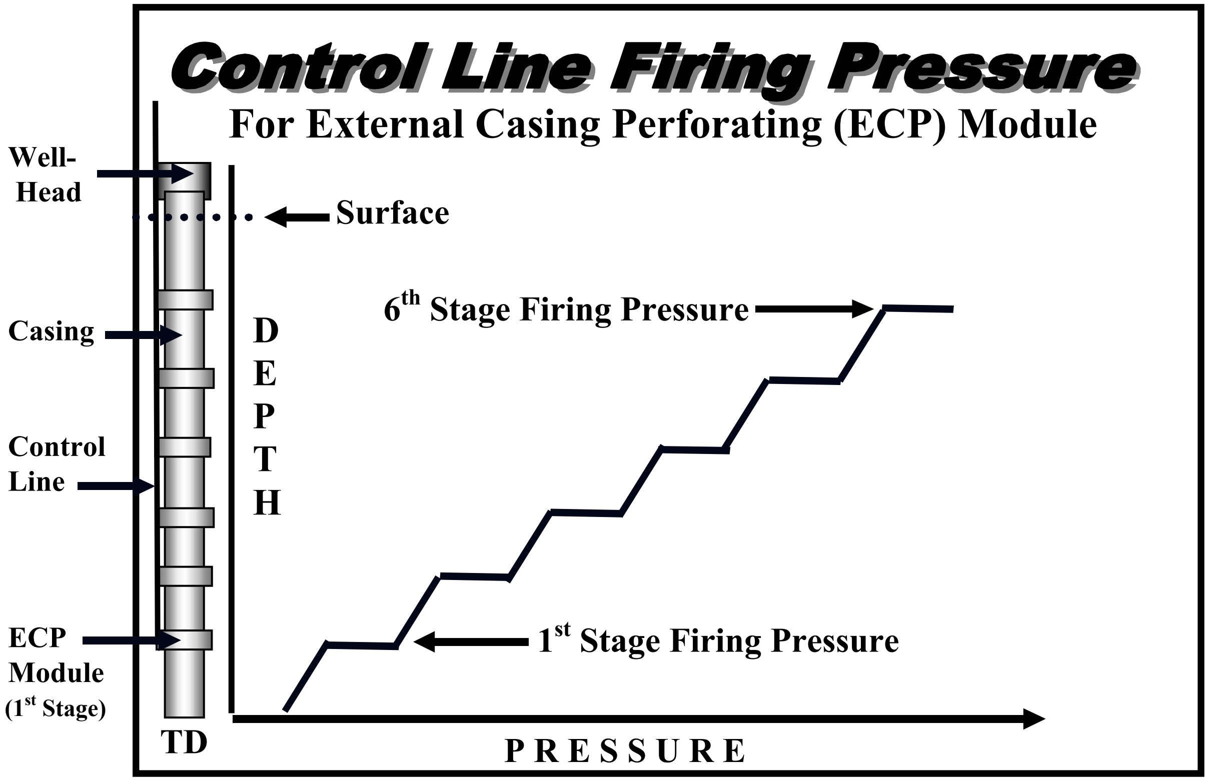


Figure 3


Control Line Firing Pressure
For External Casing Perforating (ECP) Module
Well-
Head
Surface
Casing
Control
Line
ECP
Module
(1st Stage)
TD
D
E
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T
H
6th Stage Firing Pressure
1st Stage Firing Pressure
P R E S S U R E

Figure 4

Table 1

AVERAGE COSTS PER WELL	
I. Cost Reduced due to Reduced Perforating Time with ECP (compared to bridge-plug and packer method)	
1.9 Days Less Location Cost (rig time, perforators, labor etc.)	$34,200
1.9 Days Less Fracture Equipment Cost (and related costs)	$28,500
TOTAL (Reduced Cost Potential in ECP Time Savings)	**$62,700**
II. Cost Reduced Due to Reduced Time to Sales (ECP averaged 0.9 days to sale line; 18.4 days with bridge-plug and packer method)	
17.5 Days Less Nominal Cost (rig time, drilling equipment and related costs)	**$87,500**
III. Cost Reduced due to Reduced Treatment Volumes	
Reduced Volume of 58,000 gallons (water and frac tank rental)	$2,745
Reduced Chemicals Costs on 58,000 gallons (polymer, surfactants, biocide, etc)	$21,961
TOTAL (Reduced Treatment Volume Costs)	**$24,706**
IV. Cost Reduced due to Reduced Hydraulic Horsepower	
Reduced hydraulic horsepower due to reduced treatment rate	**$3000**
V. Cost of External Casing Perforating (ECP)	
External Casing Perforating Costs	**($150,000)**
V. Other Costs (Not Included in Net Cost Reductions)	
17.5 Days Earlier Production ($4/mcf @1000 mcf/day)	$70,000
Recovery Cost of 1,381 bbls (reduced from treatment in equipment, time, etc.)	
VI. NET COST REDUCTION	
$62,700 + $87,500 + $24,706 + $3,000 – ($150,000) =	**$27,906**