2009 NATIONAL TECHNICAL CONFERENCE & EXHIBITION, NEW ORLEANS, LOUISIANA

AADE 2009NTCE-02-03:

Production Results From A New Horizontal Completion Method in the Barnett Shale

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Abstract

This paper describes the production results of an efficient multi-stage horizontal open hole completion technique that was used as an alternative to conventional horizontal open hole barefoot or cemented and perforated lateral completions. The open hole technique was applied in the Barnett Shale in North Texas. This paper will discuss the new horizontal completion system that was run as part of a production liner that does not need to be cemented and provides mechanical diversion at specified intervals. It will consider the system details as well as the fracturing methods used, compare the operational efficiencies of the system with other horizontal completions methods, and comment on differences in completion methods between two pairs of wells that were drilled offset to each other: one well in each pair was completed with the new system. Production data was gathered for each of these four wells and was then totaled every 30 days, and 360 day cumulative production totals and monthly totals will be examined.

Introduction

The Barnett Shale, a very tight gas shale (0.0009 md to 0.008 md), was inadvertently discovered in the mid-1950's but was not recognized until 1981, when a development well was planned on an expiring lease. The hole was drilled vertically, cased, cemented, perforated and acidized, then it was shut for further evaluation. At that point the well was not economically viable, but the reservoir was recognized. It wasn't until 2001 that the Barnett Shale Play experienced an increase in activity. There are at least four technologies that allowed the Barnett to expand: the development of economical horizontal drilling, 3-D seismic analysis, fracture mapping, and horizontal completion methods. Left unfractured, the wells will hardly produce: thus the need for them to be fractured.

Over the years many different methods have been developed to complete a horizontally drilled hole. A common method of completion is to leave the horizontal portion of the hole open and run a slotted or perforated liner down hole. Production is increased as there is more reservoir contact with the open horizontal over a vertical hole. This method, while being effective, leaves hardly any options in case later completions are necessary.

To increase the area of flow even more there is a need to fracture the horizontal. The goal is to create multiple complex fractured areas in the zone of interest and not over- fracture into an undesired zone. One theory concerning the creation of a complex fracture involves pumping in a low-viscosity liquid with a high volume of proppant. More contact area with the reservoir is gained when a complex fracture system is created; in a tight gas reservoir it is crucial to create as much contact with the reservoir as possible to increase flow.

A second method involves drilling the horizontal and leaving it open. A frac string is run in the open horizontal hole to the toe and fracing commences. Using a slickwater frac, the operator would then try to fracture the horizontal further by pumping a pad of water down-hole at a high rate to create a more complex fracture system in the reservoir. The next step involves a standard fracture procedure, pumping as much frac sand immersed in a cross linked gel-as possible down-hole to - create a complex fracture system at the toe of the horizontal. The frac string is then pulled back a few hundred feet and the slickwater frac procedure is repeated until the shoe was reached. Once this process is completed, the well is flowed back and production begins. There is, however, a problem with this method. If the zone that is going to be fractured is not closed off from the others, the fluid will continue to flow to the zone of least resistance. Essentially one zone of horizontal would be fractured over and over. This will cause numerous problems in the reservoir. Creating only one gigantic fracture will over fracture the reservoir in a particular spot. This will increase production, but the well may still not be economically producible. If there is a water zone present in the over fractured region the reservoir, the fracture could breach it. This would cause the wellbore to load up and stop producing prematurely. If a refrac were desired in the future, the process would have to be repeated.

A third method used to complete horizontal wells is to run and cement tubing along the horizontal. A composite plug is then set toward the toe and a perforation gun is pumped down hole to the desired location. After the tubing is perforated, the gun is pulled out of the hole and fracing can commence as outlined above. Once the first zone has been fraced, the process is repeated until the wellbore is completed. This is known as the "perf and pump method" (See Figure 1).

After the "perf and pump" completion method is finished a work-over or coiled tubing rig has to come in and drill out all of the composite plugs to reestablish flow from all fractured zones.

Once this has been accomplished, the well is flowed back and production begins. This method has a few set backs as well. First, it depends highly on a good cement job, one in which - the cement is uniform around the outside of the tubing. If it is not uniform, the perforated zones will not be isolated. If the perforated zones are not, the frac will go to the zone of least resistance. Again the possibility of over fracturing (the reservoir must be considered. If a water zone were hit, the well might be saved, although a very difficult and time-consuming squeeze job would be required.

None of these methods satisfies the needs of the industry. They are all time- consuming and costly, and they share the significant risk of over-fracing into a water zone. In addition, if isolation is not achieved, production will not increase as desired. A new system has been developed: one that isolates each zone and allows mechanical diversion so that it can be individually fraced.

After the horizontal section of the well is drilled, the process of installing the new system begins. Most of the time a reamer is run downhole to ensure that problem sections of the wellbore will be cleared out. The hole is then circulated and the drill string is tripped out. Once the drill string has been removed, the first tool is brought up to the rig floor and tested to ascertain that flow can be achieved through the tool's float valves and that circulation can be achieved while tripping in with the system. The distance between completions tools can be designed as needed on site. After a few joints of tubing have been run in hole, a hydraulic fracturing port is run in hole on the completion string. A few more joints of tubing are added, and then a pressure activated dual element packer is run in hole. A few more joints of tubing are run and then a ball activated fracturing port is run in hole. Short sections of tubing are then alternated with a pressure actuated dual-element packer and a ball activated fracturing port the desired number of times: twelve fracturing ports for a 7" tool and 14 fracturing ports for a 9-5/8" tool. An unlimited number of packers may be run in hole. The last completion tool to be run in is a liner hanger packer. The connection above the liner hanger packer is the drill string. (See Figure 2)

Once the completion system has made it to the end of the horizontal, circulating the well begins. A small ceramic ball is dropped inside the drill string, and then pumped downhole with the circulating fluid. Once it has reached the toe it will seat in a hole in the toe tool, shearing off pins to prevent circulation and communication with the annulus. Pressure is slowly built back up in the completion string and the liner hanger packer is set. The liner hanger packer has an internal one-way ratcheting system that comes into play when the shear pins of the liner hanger break because of the pressure increase. The liner hanger is a single-element packer with steel slips that are broken when the packer is set. Finally, pressure on the annulus is increased to guarantee that the packer has set and isolation from the annulus to the horizontal is achieved.

After isolation is confirmed, even more pressure is put on the system and the shear pins on the packers break off. When the system is pressured up internally, shear pins are sheared and like the liner hanger, the packers utilize an internal one way ratcheting system to keep the packers set and zones completely isolated. After the packers are set, pressure is decreased and the drill string is rotated off the liner hanger. The drill string is then tripped out of the hole and, if desired, a seal assembly is run in hole along with the rest of the production tubing and stung into the liner hanger.

The drilling rig is then moved off site and a fracturing company will rig up to the well-head. The production tubing will again be pressured up until the hydraulic frac port opens. Once this occurs, the first stage of fracing can commence. After the first stage is completed a ball is dropped inside the tubing and is pumped down to the end of the string until it seats inside a sleeve that it cannot pass through. Pressure is built up once again (See Figure 3). Fracturing of the second stage can now commence. After it has been completed, another slightly bigger ball is dropped inside the tubing and pumped down until it reaches another fracturing port located up hole from the first one. The process is repeated all the way up the string until all the fracturing ports are open. Production can begin as soon as the well is flowed back.

Advantages

There are many advantages to using a system like this. One is the possibility of modifying the system on site before it is run in hole to change the number of stages, the stage spacing, or both, and for isolating areas such as faults that do not require stimulation. Like any other completion system, it can be run in with the drilling rig. It can also be set using most drilling rigs' pumping systems. The shear pin shear rates in both the setting tool and packers may also be changed at the site. The packers have dual elements that can expand to twice their original outer diameter incase of hole enlargement or ovalities. There is no need to use perforation guns to get to the pay zone when fracturing the well, so no perforation damage to the reservoir can occur. High fracturing pressures can be established and zone isolation can still be achieved because of the dual-element packer's strength.

Another major advantage with the systems run *on the specified wells* is the reclosable fracturing ports. At a later date the wells could be refractured without having to use a rig or workover rig. Each fracturing port could be closed and the initial fracture procedure repeated by again dropping balls.

This type of system has been in use for more than six years all over the world, in over 1,000 wells in the United States alone. It has worked successfully in chalks, conglomerates, carbonates, sandstones, shales, and coal. The system has also been designed specifically to work at high pressures and high temperatures. The effectiveness of the packer elements in providing zone isolation, which decreases the chances of over fracturing a particular layer has been proven with micro-seismic analysis. Being able to fracture continuously also saves time. No additional work is needed once the initial fracture has been completed; however, the internal sleeves can be milled out with a carbon mill if desired.

The Wells

This study will review four wells which were drilled and completed by Eagle Oil and Gas in the Denton County, Texas area of the Barnett Shale. The analysis will include the fracture procedures and the production results in each case. The owners have asked that the wells not be identified, so they will be referred to by number.

Well 1 was completed in mid-2004 as a seven-stage system with a 3,300-ft horizontal. A total of 1,276,503 lbs of proppant pumped with 111,314 bbl of fluid. In just under 21 hours all seven stages were pumped continuously at rates from 60 BPM up to 140 BPM and pressures from just above 4,500 psi to above 8,000 psi. This well was completed by setting seven-inch casing around the curve to the horizontal and then drilling the horizontal with a 6-1/8" drill bit. The completions system was then run in hole on 4-1/2" 11.60 ppf liner.

Well 2 was drilled 1,000 ft parallel offset to Well 1 (See Figure 4). The horizontal had 4-1/2" 11.60 ppf liner with four zones with two sets of five-foot perforations. It was completed using the perf-and-pump method. A total of 1,273,745 lbs of proppant was pumped with 84,831 bbl of fluid. Pump rates were as high as 93 bpm and pressures were around 3,200 psi while fracing.

Wells 3 and 4 are also offset to each other (See Figure 5). Well 3 was a 9-5/8" seven-stage system run in an 8-1/2" drilled hole with 5-1/2" liner. After the rig moved off location, all seven stages were fractured in just over 22 hours. A total of 1,469,451 lbs of proppant and 97,541 bbls of fluid were pumped, with pressures just over 2,200 psi. Well 4 was lined with 5-1/2" 17 ppf, P-110 liner. The horizontal had two zones, with three sets of 5- ft-long, 180-degree staged perforations. A total of 1,303,159 lbs of proppant and 74,063 bbls of fluid were pumped, with average pump rates of 120 BPM and pressures reaching over 6,500 psi.

Production Results

The production data, which included water, oil and gas production numbers were given on a day-to-day basis. This report focuses on gas figures alone. Thirty-day totals and one year cumulative production figures for all four wells will be discussed.

After coming on line, Well 1's first thirty day production figure totaled 122,504 SCF compared to Well 2's first thirty day production of 54,846 SCF (See Figure 6). - Well 1 produced 67,658 SCF (223%) more than Well 2. After 360 days of production, Well 1's total was 807,478 SCF and Well 2's was 331,665 SCF; a total of 475,813 SCF (243%) more was produced by Well 1 (See Figure 7).

Well 3's first thirty day production was 29,659 SCF compared to – Well 4's 30,586 SCF (See Figure 8). Because Well 3 was shut in for nine days during that production period, the well was producing an average of 1,200 SCF per day, which would have put its production well ahead of Well 4's production. After 360 days of production, Well 3's total production was 217,398 SCF and Well 4's was 120,738 SCF; a total of 96,660 SCF more, that is a 180% increase (See Figure 9). After 690 days of production Well 3 produced 299,008 SCF and Well 4 produced 176,046 SCF.

The production results are significant because the wells are parallel offsets to each other with different completion methods. The wells with the new completions system produced better compared to the wells without. The average 360 day production rates for horizontals drilled in the Barnett by 2006 were only 390,000 SCF; Well 1 produced more gas when it was completed back in 2004. Well 3 did not produce as well as the entire field did on average but it did produce much better than its offset well.

Conclusions

Advances in horizontal drilling technologies have allowed the possibility of uneconomically producible reservoirs to become marginal producers. Companies can now take advantage of what were previously considered uneconomically producible reservoirs. The real production increase comes from the completion method chosen. There are many different methods that may be used to complete a horizontally drilled well, but the greatest increases are seen with fractured wells. Even greater production results are achieved when there are multiple zones of fractures in the horizontal. There are few methods that can be applied to create multiple zone fracturing. A few years ago a completion system was designed specifically for this type of application. Multiple different production results have shown an increase in production. Data from many drillings have proven that it increases production over normally completed horizontals. Multiple zone fracturing using the mechanical diversion of fracturing ports and zone isolation has been proven by the dual-element packers. There have been over 1,000 wells completed in the last six years with this system in the United States alone. The fact that over 1,000 wells have used this method suggests that it is not only a reliable method but is also an economical method.

References

1. Steward, Dan, The Barnett Shale Play: Phoenix of the Fort Worth Basin, A History. Kansas City: Fort Worth Geological Society, North Texas Geological Society, 2007.
2. Lohoefer, D., Athans, J., Seale, R., "New Barnett Shale Horizontal Completion Lowers Cost and Improves Efficiency," SPE Paper 103046, presented at the 2006 SPE ATCE, San Antonio, Texas, September 24-27, September 2006.

Acknowledgments

The author would like to thank and everyone at Packers Plus for their endless amount of support.

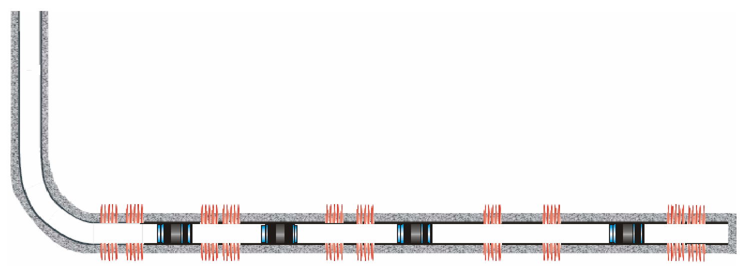

Figure 1- shows what a *Perf and Plug Method* looks like.

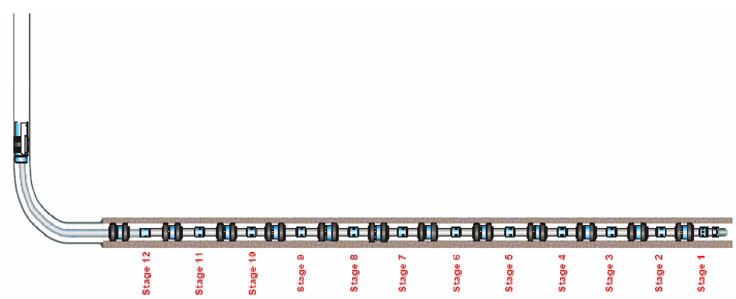

Figure 2- shows what a completions system looks like.

Figure 3- shows the pump rates and pressures during a frac to illustrate the ball drops and ball landing.

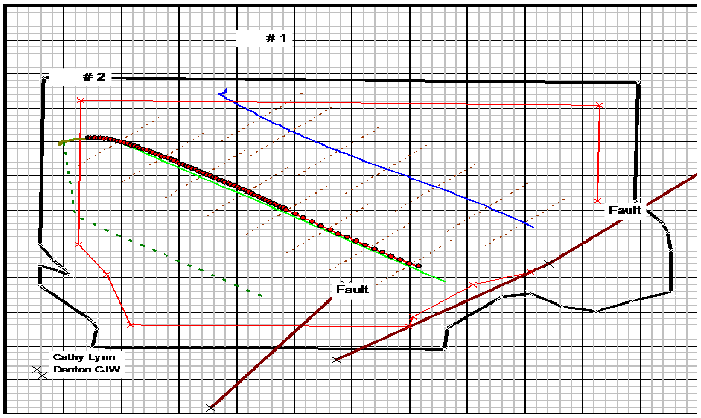

Figure 4 –illustrates how Well 1 and Well 2 were drilled parallel to each other.

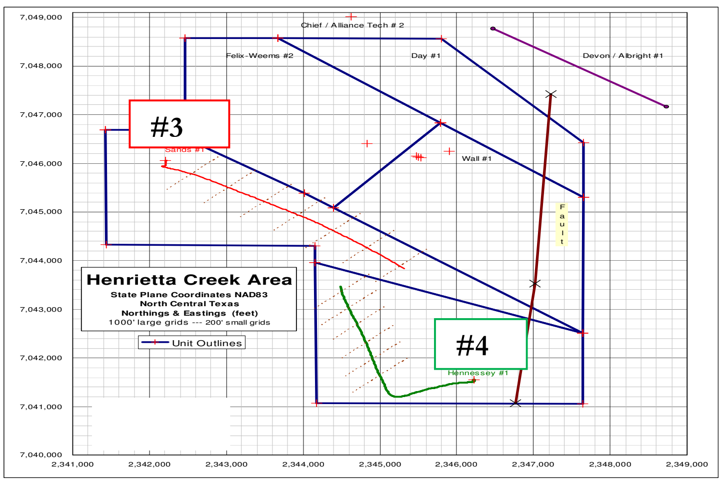

Figure 5 –illustrates how Well 3 and Well 4 are offset to each other.

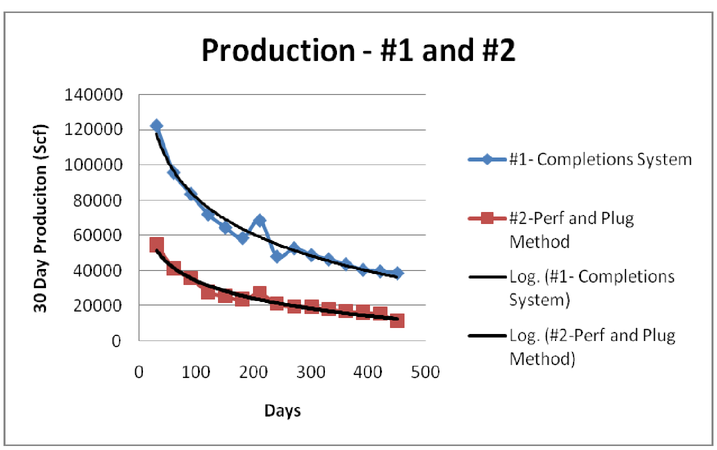

Figure 6- shows cumulative production for 30 day periods for Wells #1 and #2.

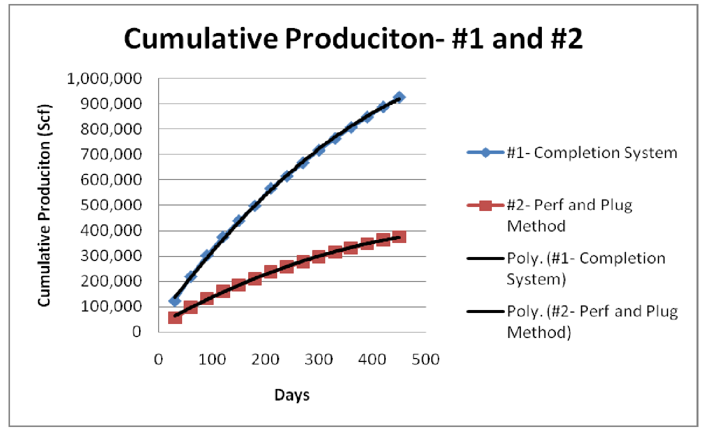

Figure 7- shows cumulative production for Wells #1 and #2.

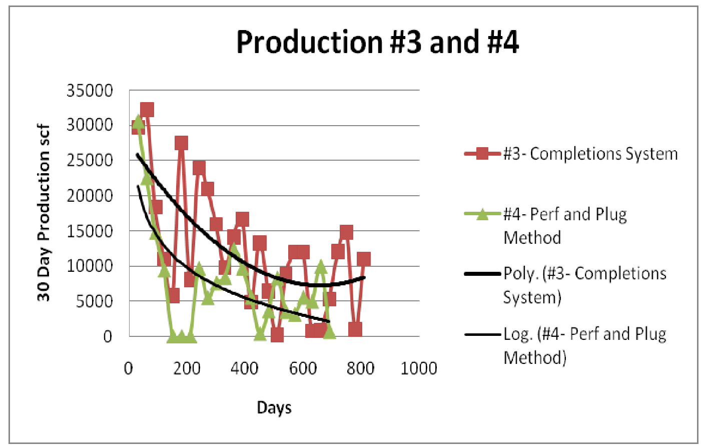

Figure 8- shows cumulative production for 30 day periods for Wells #3 and #4.

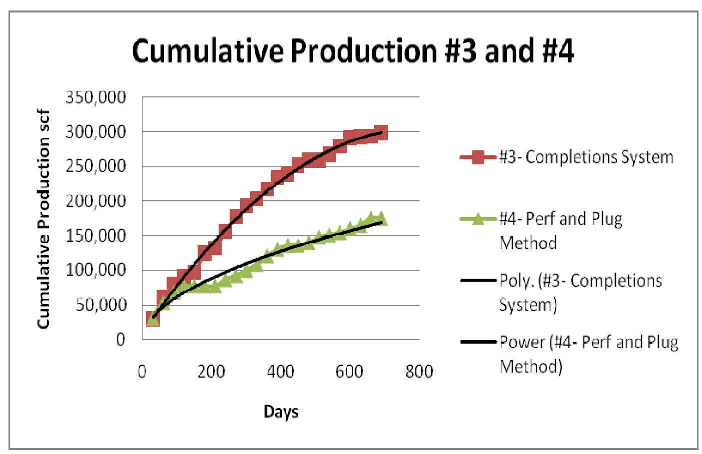

Figure 9- shows cumulative production for Wells #3 and #4.