FURTHER DEVELOPMENTS UTILIZING CASING PLUNGERS IN MULTIPLE ZONE STRIPPER WELLS AND MULTIPLE PERFORATIONS IN BARNETT SHALE

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ABSTRACT
Building on recent innovations and repeated successful applications using the multiple patented PAL PLUNGER casing plungers in multiple zone stripper gas wells in the Oklahoma Panhandle, the technology was successfully tested in 7 vertical wells drilled in the Barnett Shale in Cooke County, Texas. Prior to the installation of casing plungers, the primary method of fluid removal employed large pump units powered with gas fired motors. The issues addressed and the solutions devised, along with the results will be presented for information and discussion.

HISTORY
Recent innovations and new patents available to the industry have successfully broadened the range of applications in which casing plungers can be used to remove well bore fluids from low volume gas wells unable to sustain the critical velocity necessary to remove fluids from deeper wells common in the industry. Patented improvements in the mechanical actuation critical to the proper functioning of casing plungers have dramatically increased the reliability and opportunities for successful installations. Additionally, advances in the formulations of compounds selected have produced elastomeric cups that react with more stability and longer wear in many applications. Field engineering procedures have obtained specific well bore data that have led directly to improvements in the engineering design of sealing cups with improved performance characteristics. Well head equipment has been redesigned to facilitate ease of handling and field redressing of plungers.

While many improvements have occurred in the design and utility of casing plungers, one of the more serious limitations, heretofore, has been the requirement to locate the plunger landing stop above the top perforation. The obvious advantage of removing fluids from all horizons of perforations has been, heretofore, limited by the actual physical conditions encountered in most, if not all, well bore perforations. Typically, intervals of several too many feet of production zones are perforated, then acidized, and/or otherwise stimulated or fractured. The result, in most cases, leads to an interval of casing that has multiple perforations which become communicated across the perforated interval during the subsequent stimulation treatment. While this opens up the formation for recovery of hydrocarbons, it virtually renders the use of a casing plunger impossible in recovering fluids below the top perforation. Even though the casing plunger can descend to the lower perforations, it becomes impossible to maintain the essential seal around the sealing cups since the pressure build up below the casing plunger simply leaks out into the formation, around the casing plunger and back into the production casing choosing the path of least resistance.

The first known use of Hybrid Casing Plungers was presented to this forum in April, 2009. This paper will include an update of that initial installation.

In addition, the initial phase of this technology was tested on multiple wells in the Barnett Shale in Cooke County, Texas, during the fall of 2008 and 2009. An improved conventional casing plunger was installed on 7 wells. Typically, the shale thickness of 600 feet was perforated in 16 foot perforated intervals spaced uniformly at fifteen elevations over the shale bed. Conventional pump jacks and tubing plungers were used to remove the frac fluid and formation fluid. The improved conventional casing plungers were installed within the static fluid column above the top perforation, typically at about 8000 feet. In each well, the collar stop was placed higher than the top perforation until sufficient fluid had been removed to allow the collar stop to be lowered to just above the top perforation. A period of several months was required for this fluid removal to successfully occur. In some cases, the improved conventional casing plunger successfully replaced a conventional pump jack installation as the sole source for fluid removal. During the year, the improved conventional casing plunger clearly demonstrated the efficient removal of well bore fluids and maintained, or improved, gas production. These wells are now ready for the next stage of fluid removal from lower perforations with the use of a HYBRID CASING PLUNGER. Hopefully, these wells will be tested early in 2010 in time for results to be included in the open forum in April 2010.

DESIGN CONCEPT

Removal of well bore fluids in flowing gas wells depends primarily on maintaining the critical velocity of the gas necessary to "lift" fluids. Well depth, fluid composition, tubing diameter, reservoir pressure, and surface conditions are well known parameters for such calculations. However, the shorter the height to lift the fluids, and the smaller the diameter of the tubing, contribute to substantially lower critical velocity requirements. Typically, the separations between the top and bottom perforations are small compared to the overall depth of the well. The hybrid casing plunger incorporates these physical conditions into the design of a typical casing plunger in the following manner.

The standard collar or casing stop is replaced by a wire line set collar stop that has a clear inside diameter bore. The stop can be set just above the top perforation, some distance higher, or even above a casing obstruction. The stop becomes a landing for a customized packing assembly that is also set with a standard wire line such as a swab line. The customized packing assembly incorporates the following essential design elements. The customized packer must present an effective seal between the packer and the casing wall. The seal is accomplished by compressive forces expanding an elastomeric cup to seal against casing wall. Since the packer is run on standard wire line, the typical weight of the tubing string is not available to provide this essential compressive force. In this unique application, a section of tail pipe of smaller diameter able to pass through the inside bore of the casing collar and of sufficient weight to provide the required compressive force to seat the packer is provided. One further essential element of this design is to provide a ball and seat configuration by which fluid that is above the collar stop/packer elevation is held and subsequently removed by the next cycle of a standard casing plunger.

So, in reality the hybrid casing plunger is a very short gas well that only needs a critical velocity to lift fluid from the bottom perforation to the stop/packer elevation. Further, the gas well only needs enough pressure and flow rate to then lift the casing plunger to the surface with a load of fluid from the stop/packer.

Since gas wells typically lose flow rate and pressure in normal decline and exhibit fluid loading which restricts and ultimately stops production, various methods of artificial lift are typically employed. The hybrid casing plunger offers an economical and reliable alternative to standard pump jacks for removing low volumes of well bore fluids from weaker gas wells. In some cases, the hybrid casing plunger will perform with higher recoveries of gas and fluid than standard tubing plungers.

Actual bottom hole pressure data indicates that essentially all fluid can be removed between the perforations and lifted to the surface providing lower back pressure against the formation limited only by surface gathering system pressures.

One further significant element of design addresses the field conditions encountered with casing plungers. Typically, after the tubing is removed from the well bore and a casing plunger installed, the tubing is moved to other locations for standard field use or held as surplus inventory. Therefore, the hybrid casing plunger with the unique customized packer element should be reliably inserted and retrieved with standard swab rig equipment. While slick line will likely be suitable for setting the open bore collar stop, the standard swab rig offers several critical benefits for installation. One obvious benefit is the heavier loads that are permissible with the swab rig. But another equally critical benefit will be the height of the swab rig derrick. Since the tail pipe will generally be standard oil field equipment such as 1 ¼ inch or 1 ½ inch integral joint tubing of typical lengths of about 30 feet, the derrick height will enable single joints of tubing to be picked up and threaded into the tail pipe assembly, and since the overall length of the tail pipe might be several hundred feet, the heavier swab line and derrick will be both suitable and preferred. The use of a standard swab rig to insert and retrieve the down hole assembly is much more cost effective than returning to the location with tubing and work-over rig.

WELL SELECTION

A well in the Oklahoma panhandle was chosen for the initial test well. This well was producing with a standard casing plunger with two production zones separated by about 300 feet. A standard bottom hole pressure profile was obtained across both zones and the hydrostatic gradient between the zones was calculated to be about 0.229 psi/foot. This gradient is typical of fluid loaded zones with some gas flow to reduce the typical gradient of static fluid. The collar stop was initially placed just above the top perforation in the normal procedure. However, it was determined that the collar stop could be raised an additional 40 feet, or more if necessary, and the hollow bore collar stop was set with standard slick line equipment to ascertain the exact location. The customized packer was designed and fabricated to be set on the collar stop using a standard swab rig. Further, incorporated into the initial customized packer and down hole assembly were remote pressure and temperature recorders that would provide a historical collection of hydrostatic pressure measured above the packer and at the bottom of the assembly at the lower perforations. The tail pipe assembly was constructed using standard 1 ¼ inch IJ flush joint tubing. This size pipe was both structurally strong enough for the bottom hole assembly and the outside diameter of flush joint upsets passed easily through the open bore of the collar stop. The length of 350 feet of tubing supplied more than enough weight to provide the compressive force necessary to seat the packer and maintain an adequate casing wall seal throughout the normal operation of the hybrid casing plunger application. A standard pump ball and seat were incorporated into the design to provide the fluid seal that would be required to hold the fluid above the packer until the next cycle of the standard casing plunger.

The wells in the Barnett Shale were drilled and completed with 5 ½" 17 #/ft casing. Typically, the top of the formation was at 8000 feet and the bottom was at 8600 feet. Standard flanged well heads were initially installed. Prior to the installation of the casing plungers, the tubing was removed, and then a packer was set on tubing at about 1500 feet. The remainder of the tubing was removed, the packer was covered with water and the B-section and well head was removed. A standard 5- 1/2" bell nipple with 8rd thds was welded onto the top of the casing. The well was then fitted with a full port 5-1/2" 2000 psig ball valve and with the lower section of the casing plunger lubricator installed. Then the casing packer was retrieved and all the tubing laid down. Of course, those wells being produced with rod pump and jack had the rods and pump retrieved and laid down. The upper section of the casing plunger lubricator was installed. The casing was then conditioned with a casing scraper, the collar stop was set at the selected depth, and the casing swabbed down to scattered fluid above the collar stop. The well head casing plunger lubricator was plumbed into the production lines and the casing plunger was dropped into the casing. The descent and ascent of the plunger travel was monitored with an EchoMeter Model M fluid level instrument. The fall rate of the casing plunger provided instant confirmation that the plunger was descending into the well and below the static fluid level. Similarly, the rate of ascent could be easily determined to confirm satisfactory performance. The initial fluid levels were higher than well reservoir pressure could lift. Consequently, the collar stop was raised higher in the fluid column, the fluid swabbed and the casing plunger returned to operation. This method allowed the reservoir pressure to lift the upper portion of the gas cut fluid column and the plunger with regularity.

During this 15 month test period, several factors were identified and resolved. Excessive sand was encountered on some wells that adversely affected the sealing cup life and the lubricator catch mechanism. Sealing cup compounds were altered to provide longer life during sand production. After the sand was cleaned up, the sealing cup compounds were changed to provide longer life and better lift efficiency. As the result of testing 7 wells in close proximity, an improved cup design was tested and proved to be superior to the previous design. The improved design is now available for general use.

These wells have now had the collar stops lowered to just above the top perforation and recovered the fluid above the top perforation. They are now ready to be evaluated with the HYBRID CASING PLUNGER to determine the additional production benefits of removing gas cut fluid over the 600 feet of perforated intervals.

FIELD INSTALLATION

In the Oklahoma well, after months of operation with an improved conventional casing plunger, the smaller diameter tubing, the customized packer and down hole assembly, and a standard swab rig were brought to the location. The bottom guide shoe with an enclosed pressure and temperature recorder were calibrated and the clock was set to obtain 16,000 data points over the selected time period of the recorder clock. The guide shoe and recorder assembly were attached to a short perforated sub of the same tubing used in the tail pipe. Eleven joints of tubing were picked up, threaded onto the assembly, attached to the swab line using standard fishing tools and lowered into the well bore. The down hole assembly was landed on the collar stop. Then using standard procedures, the fishing tool pin was sheared and the bottom hole assembly was in place. The procedure for this field installation was accomplished with no anomalies and considered to have been satisfactory in all respects. Two separate tests were conducted to measure the down hole pressure and temperature. The first test lasted 11 days during which time the collection of data was maximized and the clock time expired. The removal of the down hole assembly was accomplished by using a standard swab rig and a standard fishing tool. The data was downloaded into a computer and the clock reset for a longer interval between data collection points and a longer clock time was set. The second test lasted 17 days after which the down hole assembly was retrieved with standard swab rig and tools. The pressure and temperature recorders were retrieved and the down hole assembly was replaced in the well bore for continued production. At this point, no problems have been experienced in setting or retrieving the down hole assembly using standard swab rig and tools.

In the Barnett Shale wells, other than setting the safety packer for surface welding conditions on tubing, all other work has been performed with a standard swab rig, using standard conventional tools.

RESULTS

Since the production operation of the Oklahoma well utilized a standard casing plunger for months prior to the installation of the hybrid down hole assembly, production data showed an immediate increase in production. A portion of the increase can be attributed to the shut down time which occurred during the installation. However, a significant portion of the production increase can be attributed to the additional fluid that was recovered from the producing zones utilizing the installation of the hybrid casing plunger.

The most significant data obtained was the pressure and temperature data obtained at the lower perforation and just above the customized packer. Both tests, the 11 day and the 17 day, revealed that the actual pressure difference between the recorder at the bottom perforation and the recorder above the packer and just below the point at which the casing plunger would pick up and unload the accumulated fluid was less than 3 pounds. This extremely low pressure difference must be compared to the normal pressure difference that existed prior to the installation of the hybrid casing plunger. Remember, the hydrostatic gradient determined by standard bottom hole pressure profiles indicated a gradient of 0.229 psi/ft. A height difference of 350 feet would typically indicate a pressure difference of about 80 pounds under such conditions. The actual difference measured less than 3 pounds indicating that the hybrid casing plunger was maintaining a column of gas between the zones that was essentially free of fluid. This particular well exhibited such a gradient in the upper section of the production casing above the fluid level indicating that the fluid below the packer and across the production zones had been removed to provide and an essentially fluid free production zone. This condition would represent the most favorable production scenario.

In the Barnett Shale wells, an improved conventional casing plunger has successfully demonstrated the effective removal of well bore fluids containing both treatment fluids and naturally occurring well formation fluids. In some cases, the significant advantage of removing expensive assets such as tubing, rods and pump jack were justification enough to replace such assets with the more less expensive improved casing plunger. And in each case, the improved conventional casing plunger successfully removed the well bore fluids and sustained gas production.

CONCLUSIONS

A hybrid casing plunger may offer substantial benefits in the production of wells producing from multiple zones or from thicker zones such as the Barnett Shale whereby the fluid is removed from the lower perforations using a standard casing plunger in conjunction with such a hybrid assembly. The employment of a customized packer with provisions to catch and hold the fluid in the casing above the collar stop takes advantage of the obviously lower critical velocity that a short section of small diameter pipe affords. Utilizing the gas flow below the packer to lift the fluid to the packer for subsequent removal on the next cycle of a standard casing plunger offers many advantages to the producer.

OTHER APPLICATIONS

As the result of these successful installations, several other possibilities warrant evaluation. Among these other applications to evaluate are wells in which permanent packers, once a common practice, are considered uneconomical to drill out due both to the expense and the attendant damage likely to result in weaker and depleted production zones.

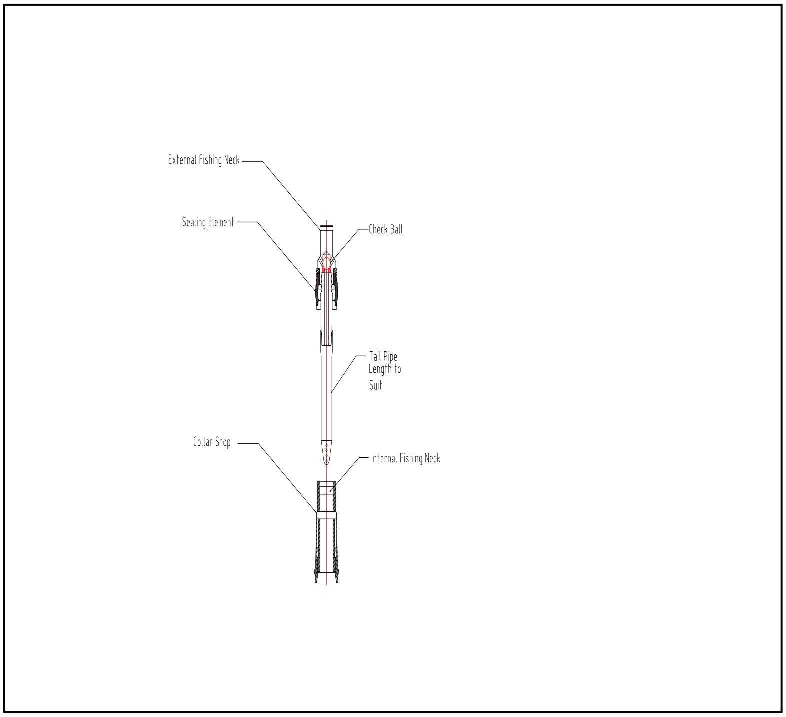
Another application may occur in which the casing has been damaged and a full bore and clean casing would prohibit the successful operation of a standard casing plunger.

And another application may well occur in a very weak well producing from a single zone in which a standard casing plunger application would still leave 50 feet or more of gas cut fluid over the perforations. Such very weak wells could benefit from the removal of even such a short column of gas cut fluid.

Still to be determined are the limits of the effective length of tail pipe that would still meet the requirements of lowering the critical velocity sufficiently to remove fluids from the lower perforations to just above the customized packer and stop assembly. This application might find use in horizontal wells where the collar stop is set in the vertical section and the tail pipe extends into the curve and beyond.

PRESENTATION OF DATA

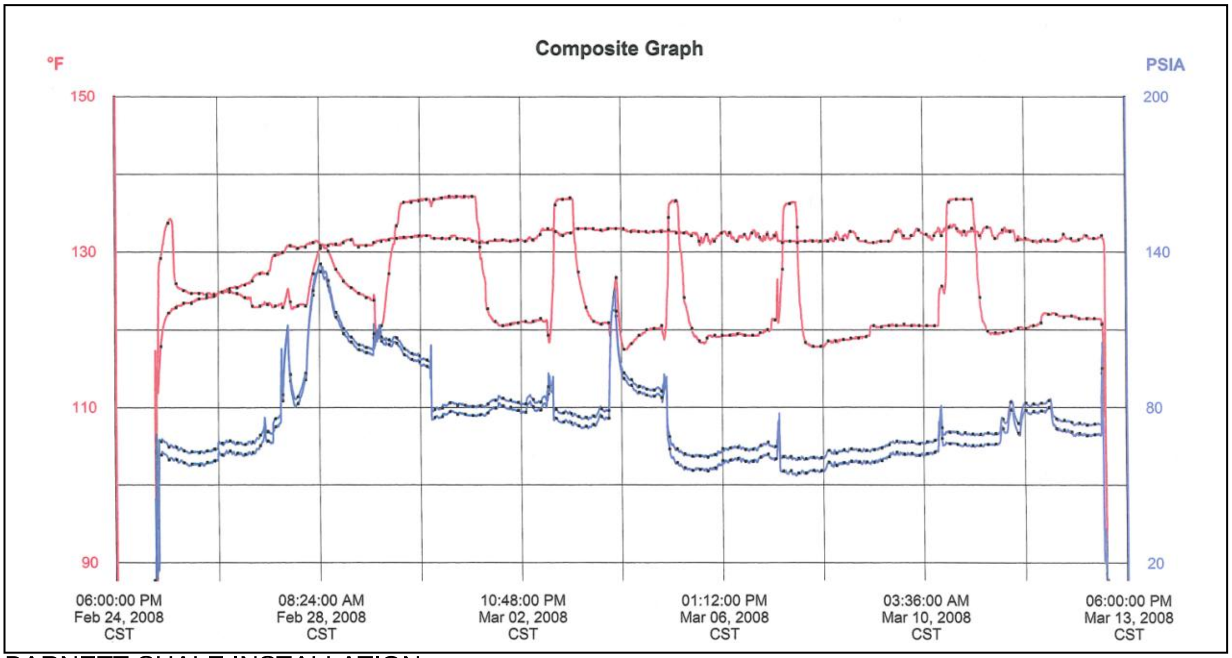
The request to keep charts, photos, and data tables to a minimum in this text has been honored. This paper will be presented in forum at the April 21-22, 2010 Production Short Course in which a broad collection of visual data will be presented for review and information. These few photos are attached as a preview. We hope to see you there.



HYBRID CASING PLUNGER DESIGN

- 4 ½” 11.6 #/FT CSG.
- CONVENTIONAL
- PERF 6026-6038
- CSG STOP 6012
- HYBRID PAL
- PERF 6026-6038
- PERF 6342-6346
- CSG STOP 5966

HYBRID CASING PLUNGER TEST WELL



BARNETT SHALE INSTALLATION

PRESSURE AND TEMPERATURE DATA AT BOTTOM OF PERFS AND ABOVE PACKER

TYPICAL WELL CONDITIONS, PERFORATIONS 8000-8600 FEET, VERTICAL.. FRAC FLUID AND FORMATION FLUID REMOVED BY ROD PUMP AND TUBING PLUNGER.