A CASE STUDY OF A LOW POLYMER ENERGIZED FLUID IN THE ARKOMA BASIN

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ABSTRACT
As with all mature petroleum fields, reservoir depletion becomes a factor, especially for wells drilled later in the life of the field. When the reservoir pressure becomes low, standard treatment fluids cannot be used effectively and other methods must be used to stimulate the reservoirs. The Arkoma Basin of Western Arkansas is no exception to this rule. This area of the basin is highly faulted and compartmentalized, which adds significantly to the reservoir complexity. Depending on well placement, there are several potential zones in each well exhibiting varying degrees of reservoir depletion.

The fracturing industry has gone through many technological advances over the years, and with these technological improvements have come many successes. Use of a low polymer energized fluid provides a good solution for these low reservoir-pressure reservoirs. These new style treatments provide faster cleanup, better flowback, better sand placement, and better production than conventional or previously utilized fracturing fluids.

The case studies will show that the low polymer energized fluid technique provides a positive response for these types of wells. Low polymer energized fluids can offer the qualities and properties to enhance completions and improve project and well economics.

INTRODUCTION
This study reviews the use of a new low polymer, energized fluid in the Arkoma Basin primarily in western Arkansas and its positive impact on these areas. A brief look at the basin, its geology, and stimulation history should give insight into the how's and why's of current stimulation techniques. While there are not many published studies in this area, a basic background of the types of reservoirs can be given. Fully characterizing each formation within the Arkoma Basin is beyond the scope of this paper. The intent of this paper is to make operators aware of what they can evaluate when making completion decisions on wells in this area.

GEOLOGY
The Arkoma Basin located in western Arkansas and extending into eastern Oklahoma, has become one of the largest and most productive petroleum areas in the United States. The basin extends for approximately 260 miles east to west and from 20 to 50 miles north to south Figure (1)[1]. The basin is bounded on two sides, by the Ouachita overthrust belt to the south and the Ozark uplift to the north. Because of the stresses that these boundaries incurred, the basin has undergone extreme folding and faulting, which created a sequence of east to west trending anticlines and synclines throughout the basin. These are again influenced by normal faults that run southward to the basin's dips[1].

Most gas production from the basin is related to anticlinal or fault-trap structures where adequate porosity was preserved for hydrocarbon accumulation Figure (2)[2]. Today, more than 30 different producing zones have been discovered which range in age from the Cambrian to the Pennsylvanian[2]. In this study the Atokan series sands of the Pennsylvanian age will be the primary zones of interest.

The Atokan sands were deposited in a delta environment. Most reservoirs are lenticular sandstones, typically composed of fine to medium grains, and are described as shaley. The Pennsylvanian sands are bound by strong shale barriers that help limit fracture height growth. The Atokan sands thicken from east to west to the Oklahoma State line giving Arkansas more productive horizons than Oklahoma.

RESERVOIR BASICS
Sufficient effective porosity development is essential for gas production. There are four types of porosity typically associated with sandstone reservoirs: intergranular, dissolution, fracture, and microporosity. Neither naturally occurring fractures nor fracture- related porosity was found to be significant in these Atokan formations[3].

The Pennsylvanian reservoirs can be placed into three category types:

Type I –relatively high φ(>10%) and relatively high K (>1 md)
Type II –relatively low φ(< 10%) and low K (< 1 md)
Type III –relatively high φ(>10%) and low K

One third of all Arkoma Basin Atokan completions are in Type I reservoirs. These reservoirs contain intergranular porosity with well-connected dissolution porosity. The high quality of these sandstones can be recognized on wireline logs. These reservoirs are only limited by faults, pinchouts and water encroachment[3].

Type II reservoirs have considerably less intergranular and dissolution porosity but more microporosity. Authigenic precipitates such as clay minerals and quartz overgrowths can result in high surface areas with small pores and high water saturation. Type III reservoirs contain predominately dissolution porosity that is the result of the leaching of soluble matrix materials. These typically have very low permeabilities.

Typically the Type I and II reservoirs are characterized sufficiently. Type III reservoirs, however, are difficult to define. Because they appear similar to Type I but do not produce hydrocarbons, they are considered underachievers. A general consensus is that these types of reservoirs are not underachievers but rather are poorly characterized reservoirs. This lack of adequate characterization can lead to completion mistakes or unrealistically high productivity expectations, which in turn, can lead to incorrect decisions in terms of reservoir stimulation needs.[3]

These types of porosity systems in conjunction with the Atokan sand's lenticularity make these reservoirs very difficult to characterize. Geological knowledge of the reservoir is a must in this basin, not only for production goals but also for economic decisions.

FRACTURING HISTORY

Since most wells in the basin exhibit permeabilities of less than 1 millidarcy, hydraulic fracturing has been the typical stimulation technique since the 1960's.

Many fluid types have been applied in the basin, ranging from linear gelled-water treatments to the 65-75 quality foam fracs currently in use. Three percent gelled hydrochloric acid was used as a base fluid for many years before clay stabilizers became commercially available. Diverse hydraulic fracture propping agents were also employed, ranging from walnut hulls to sintered bauxite. These varied depending on the closure stress of the formation. Ottawa sand is the primary proppant of choice in hydraulic fracture treatments today. Early crosslinked fluids were primarily borates. These could handle larger concentrations of sand up to 8 ppa. As wells were drilled deeper, titanates, zirconates, and other organometallic systems were utilized. To enhance reservoir cleanup, nitrogen and carbon dioxide were added to the fluid.

As the addition of these gases to the fracturing systems increased, downhole concentrations of proppant were limited. With continued improvements in technology, the blending and pumping equipment improved sufficiently to carry concentrations up to 20 ppa. Current foamed fracturing fluids utilize nitrogen, carbon dioxide or a binary system, which commingles both gases. Most current binary frac jobs use 60 to 75 quality foam.[4]

Today, foam is the fluid of choice by most operators. This is perceived to provide the best cleanup while causing the least damage to the formation. Utilizing foam in conjunction with the low-polymer cross-linked system shows promising results from the data collected.

LOW-POLYMER FLUID

A fluid was developed in 1998 that uses a CMG (carboxymethyl guar) and a zirconium crosslinker. This system is compatible with both nitrogen and carbon dioxide, as well as a variety of surfactants, and can be used with an assortment of polymer breakers. The only disadvantage associated with this system is its incompatibility with potassium chloride (KCl). A liquid KCl substitute is added to the system for temporary clay protection. For the system to be fully effective a clean water source must also be used; most potable city waters can be utilized.

As of March 2003 there have been more than 140 fracture treatments utilizing this low polymer fluid that have been pumped in the Arkoma Basin. Almost 75% of these treatments use nitrogen to energize the treatment load. Gel loadings are from 16 ppt to 20 ppt CMG. Gas content from 65 to 75 quality foams. The fluid contains a liquid KCl substitute, surfactant, foamer, buffer, crosslinker and breakers. Since there is a reduction in polymer concentration, one would expect less damage to the proppant pack. Along with a rise in breaker concentrations one would realize an improvement in retained conductivity, thus a longer effective fracture length.[5]

DATA AND PROCEDURE

Most foamed fracturing treatments were pumped in Arkansas; therefore, this is the region of interest. The case histories in this study were from Franklin, Logan and Sebastian Counties in Arkansas. The first step in reviewing case histories was to locate all wells treated with the CMG system. This was done using a proprietary Graphical Information System (GIS) software package. Job numbers from fracturing treatments were acquired which contained the API number (unique well identifier) of the well. The GIS software plots the well locations on a map extent. The map extent was adjusted to a minimum distance to incorporate the groups of CMG-treated wells while also covering an area sufficient to obtain meaningful offset well data. This range usually extended no more than five miles. The API numbers were then entered into the PI/Dwights database to obtain well information and production data.

The next step in determining meaningful data comparisons was to establish a series of criteria to define the wells of interest and the offset wells. The wells of interest were characterized as having been treated with the CMG fluid, containing a single producing formation and having at least one year of production data available. The offset wells were also identified as producing from the same formation; the well had been fraced, containing a single producing formation and at least one year of production data. The offset wells were also limited to first production after 1995.

Normalizing each well's production relative to the amount of proppant pumped into the hydraulic fracture, interwell comparisons were made. This was carried out to the cumulative production of at least the first year. Due to limited data two of these were carried to 180 days in order to be included in the study. There are several productive zones in each area, which include the Nichols, Borum, Turner, Orr, Basham, Hale, Alma, Bynum, Tackett, and the Carpenter. The low polymer fluid has been pumped in a majority of these zones, but due to limited data, some of these were excluded from this study.

RESULTS

The first area of interest is in the Gragg Field located in Sebastian and Logan Counties. The Gragg Field covers a relatively small area in these counties Figure (3). All results from this study are found in Figure (4). The first zone of interest in the Gragg Field is the Nichols Formation. There are 10 wells of interest with eight offset wells. The wells treated with the low polymer system received twice as much proppant, showing a 200% increase in production over the offsets during the first year. Normalizing the data confirms this larger increase in production.

The Turner Formation has 10 wells of interest and seven offset wells. Again, the wells treated with the low polymer system placed almost twice as much proppant, yielding more than twice the total production for the first year compared to the offset wells. Normalizing with sand placed shows an increase of 124% over the offsets.

The last group of wells studied in Gragg Field involves the Borum Formation. Because of the limited number of wells that meet the study criteria, only 180-day production was used. There are four wells of interest and four offset wells available for this comparison. Even though slightly more sand was pumped in the offset wells (approximately 3%), the wells treated with the low polymer fluid again performed better than the offset wells. The low polymer treated wells produced 15% better than the offset wells with the sand placed in the fracture.

The second area of interest is in the Aetna Field located in Franklin County, Arkansas, which is just north and east of the Gragg Field Figure (5). The results of this study can be found in figure (6). There are four zones of interest, the first of which is the Hale Sandstone, which is one of the deeper zones. There are three wells of interest and three offset wells based on the comparison criteria. Since two of the wells had limited production, 180-day gas was the maximum used. There was an equivalent volume of proppant pumped on both the wells of interest and the offset wells. The normalized production for the low polymer system is almost three times the gas production from the offset wells. The next zone to study is the Tackett Sandstone. In this group, there are only two wells of each treatment available for comparison. Again, equivalent proppant volumes were pumped in these wells, but the average normalized production data favors the wells treated with the low polymer fluid by 50%.

The Bynum Sandstone is one of the next zones uphole. There was only one well of interest and one offset well available for comparison. They are both very close in depth and in the sizes of the hydraulic fracture treatments. The well receiving the low polymer fluid treatment yielded twice the production from the Bynum Sandstone when compared to the offset well. The

Carpenter zone has similar circumstances in that it has only one well of interest and one offset well. The conditions are also similar in depth and treatment. Once normalized, the low polymer fluid-treated well again has significantly better production numbers when compared to the offset well. One cautionary note when reviewing these comparisons: due to the lack of a larger number of wells in these comparisons, the reservoir quality could be a significant factor in the production volumes.

CONCLUSIONS

As the Arkoma Basin continues to mature, new technologies can aid in understanding well production trends, leading to better completion practices. Since there is limited public information available in some of these areas, gathering and understanding the data can be invaluable in making optimized stimulation decisions. Understanding the types of reservoirs encountered in specific petroleum plays can make completing a well successful or less than desirable. When utilizing the low polymer energized fluid properly, the results can be very advantageous to the operator.

ACKNOWLEDGEMENTS

The author would like to thank BJ Services for support in writing this paper. The author would also like to thank all those editors who scrupulously poured over the manuscript.

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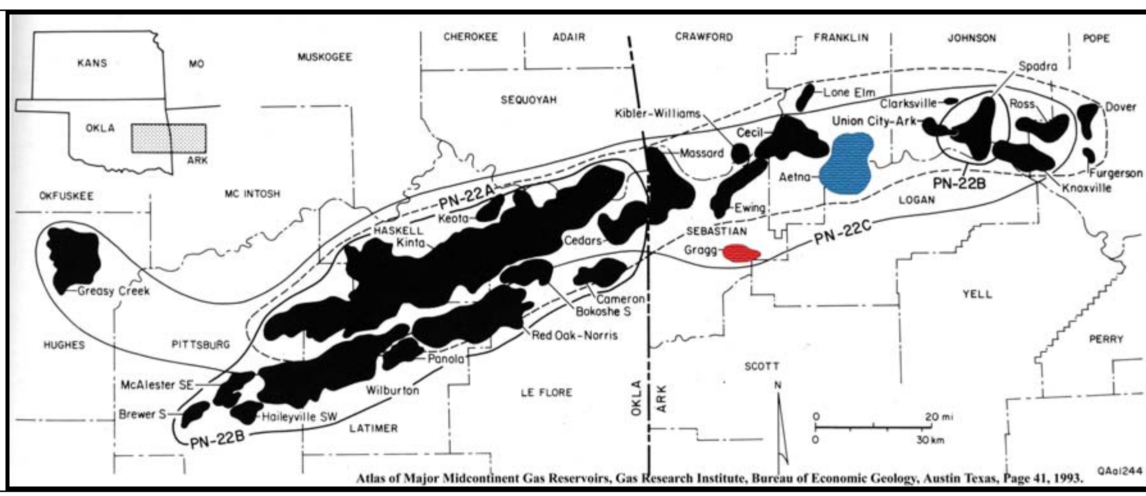

Figure 1 - Arkoma Basin

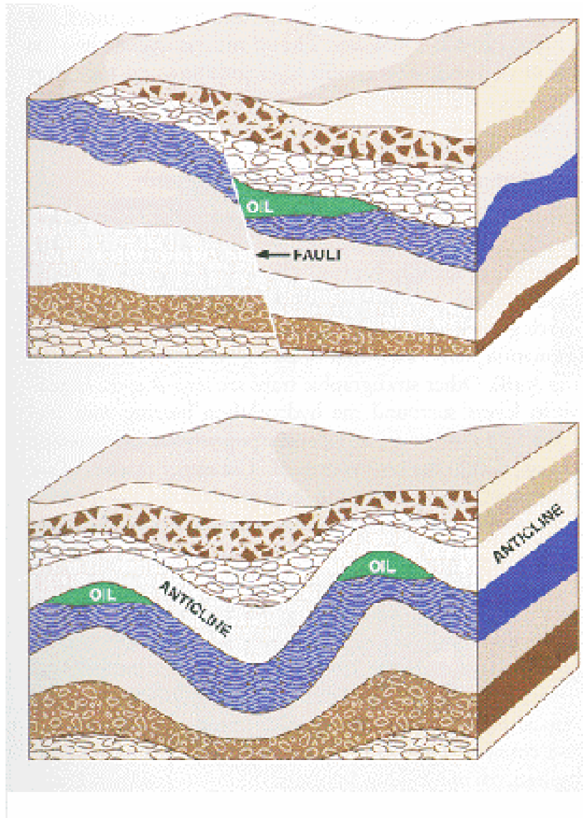

Figure 2

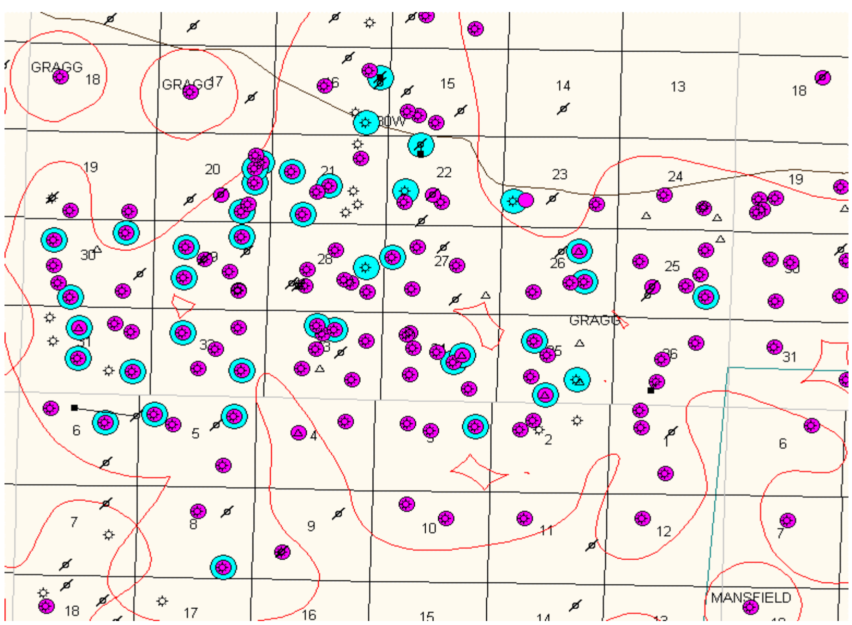

Figure 3 - Gragg Field

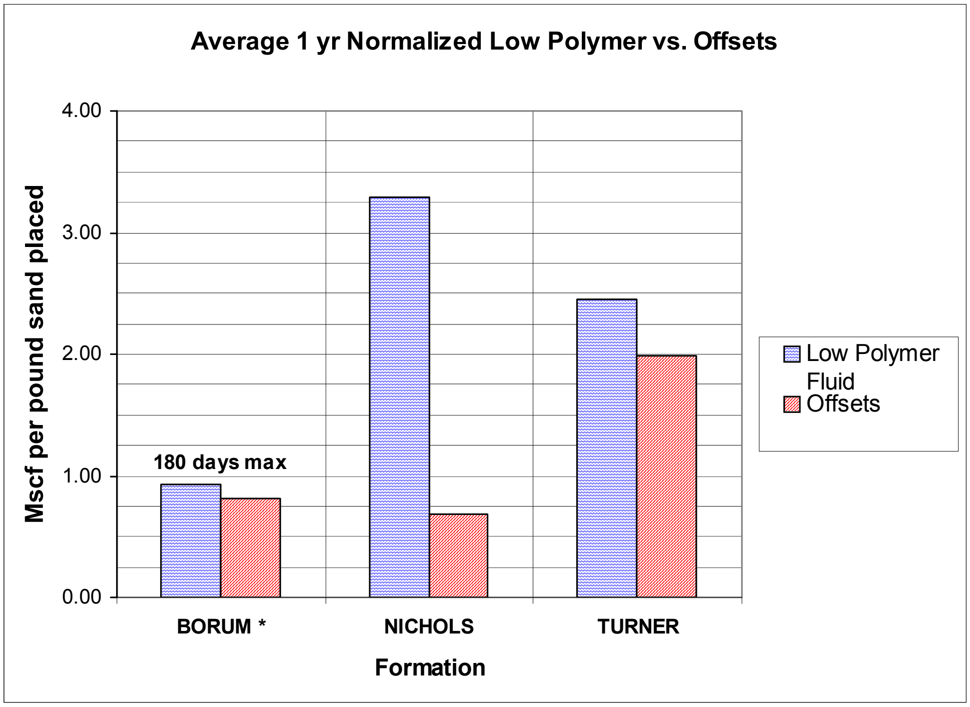

Figure 4 - Sebastian Co.

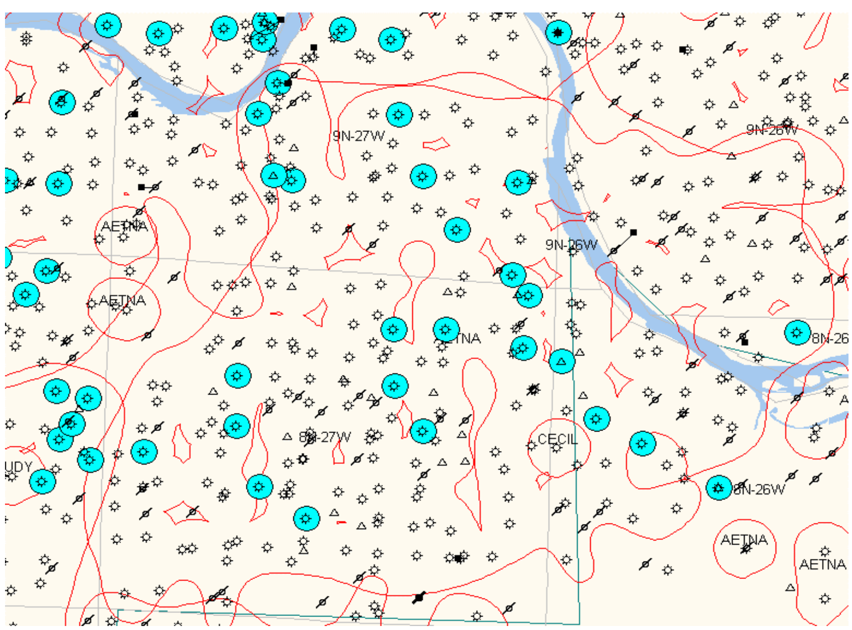

Figure 5 - Aetna Field

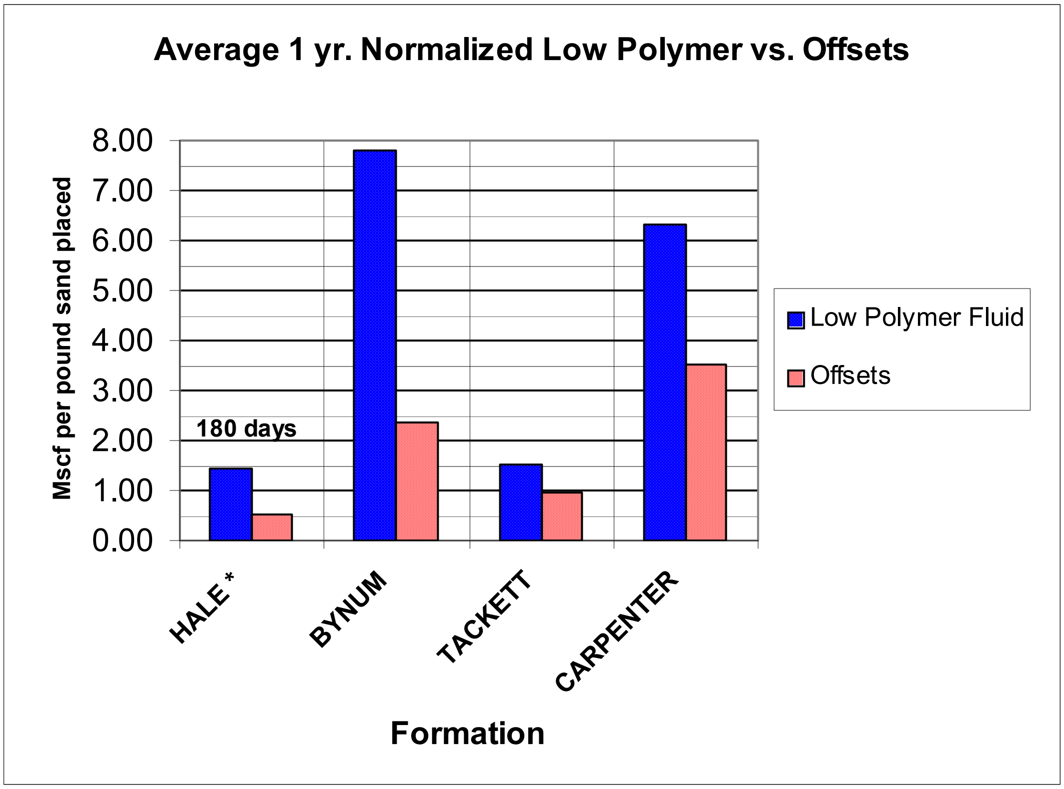

Figure 6 - Franklin Co