Aeon Energy Corp.
Polymer Gel Water Reduction Treatment
North Maxbass Madison Unit – Lillie Farms #3 Producing Well
SW-NW-10-T161N-R81W
Bottineau County, North Dakota

BACKGROUND INFORMATION

Aeon Energy Corp. is the operator of the Lillie Farms Partnership Lease (Sec 10-T161N-R81W) in the North Maxbass Field in Bottineau County, North Dakota. The Lillie Farms Partnership #3 well was drilled and completed in the late 1980's. The producing formation is the Madison, which is a dolomitic limestone natural waterdrive reservoir. The well was completed openhole (3996' - 4005'), and originally produced 5 BPD of 27.5° API crude oil and 470 BPD saltwater. By late 2006, oil production had decreased to about 2 BPD and water production had increased to 625 BPD. It was believed that natural vertical fractures connected the wellbore to a strong, underlying aquifer, and that these fractures provided a conduit for water flow. The increasingly high producing fluid level caused by the excessive water production has resulted in decreased oil flow into the wellbore. Even with a disposal system in place, saltwater disposal costs represented the single highest operating cost and the well was uneconomic to produce, even at higher oil prices.

This well has many of the same characteristics that are present in the Arbuckle formation on the Central Kansas Uplift where polymer gel treatments have been proven very effective after being applied to hundreds of wells. Like most Arbuckle wells, the Lillie Farms #3 is a stripper well that produces large volumes of saltwater and small amounts of low gravity oil (0.5-2.0% oil cut) from a carbonate reservoir at a depth of about 4,000 feet. Bottom hole temperature is around 120° F. The oil-bearing reservoir consists of dolomite with good matrix porosity and permeability, and it overlies a limestone that is an exceptionally high permeability aquifer. Reservoir pressure has changed very little over time since the underlying aquifer provides an active waterdrive for the producing zone.

In November 2006, the Lillie Farms #3 was treated with a polymer gel solution that was designed to selectively reduce produced water volumes without decreasing the oil volume. The goal was to place (by "bullheading") the polymer gel into the high permeability fractures and large vugs that connect the wellbore to the aquifer. When properly designed and executed, polymer gel treatments will significantly decrease water production, lower producing fluid levels, decrease water to oil ratio (WOR), and extend the economic life of the well. In most instances, treatments result in a significantly higher oil producing rate.

It is believed that the effects of a polymer gel treatment last longer if the treatment can be placed deep into the offending fractures; however, it is impossible to calculate the volume that is required to fill a fracture network to any given distance unless the width, height, length and number of fractures is known. It was believed that productivity index ("PI") for the Lillie Farms #3 would be a good indicator of fracture intensity. It was assumed that a high PI would indicate multiple large fractures, and that a correspondingly large volume of polymer gel would be required to fill these fractures, in-depth. Conversely, a lower PI would indicate smaller fractures, that could be filled with a correspondingly smaller polymer gel volume. Ultimately, however, the volume of polymer gel that is injected is dictated by the response observed and the individual conditions of a particular well. In the case of the Lille Farms #3, it was believed that the well had the capability of producing about 6,100 BPD of water, so a correspondingly large polymer gel volume (4,000 Bbls.) was recommended.

Prior to the polymer gel treatment, the Lillie Farms #3 was aggressively acidized at high rate and pressure that included a large water displacement. The rational for this approach was to attempt to reach as far as possible into the reservoir with acid and to help ensure that the fractures were free of scale that could inhibit polymer injection. It was also hoped that some of the acid would stimulate the lower permeability oil-bearing rock to allow higher rates of oil production after the polymer treatment.

POLYMER GEL TREATMENT

The polymer gel treatment was bullheaded into the openhole interval at a rate of 1,100 BPD (0.75 BPM), through tubing with a packer set in the casing above the top of the Madison formation. A total of 2,412 Bbls. of polymer gel were injected at a maximum tubing pressure of 975 psi. The designed volume of 4,000 barrels was not placed because the injection pressure increased during the job faster than was anticipated to the pre-determined limit. The decision was made to terminate the job prematurely to avoid forcing polymer gel into oil-bearing pore spaces.

The polymer gel solution was displaced past the wellbore with 100 barrels of water to maintain fracture permeability within the oil portion of the reservoir. It was believed that the 100 barrel water volume was small enough to avoid displacing the polymer plug to a position below the oil-water contact. If the plug was displaced too far, a connection between the aquifer and the wellbore could be re-established causing the treatment to fail. After the water displacement volume was pumped, the well was shut-in for fourteen days to allow the polymer gel to achieve maximum strength and maturity. The total cost for the polymer gel portion of this project was $26,381.

PROJECT RESULTS

After the well was returned to production, the oil and water producing rates were nearly identical to the pre-treatment rates (see Figure 1). From a production standpoint, the treatment appears to have had little if any affect at decreasing water or increasing oil production. Plots of Cumulative Oil vs. WOR and Oil Cut % also show virtually no change from historical trends (see Figures 2 and 3).

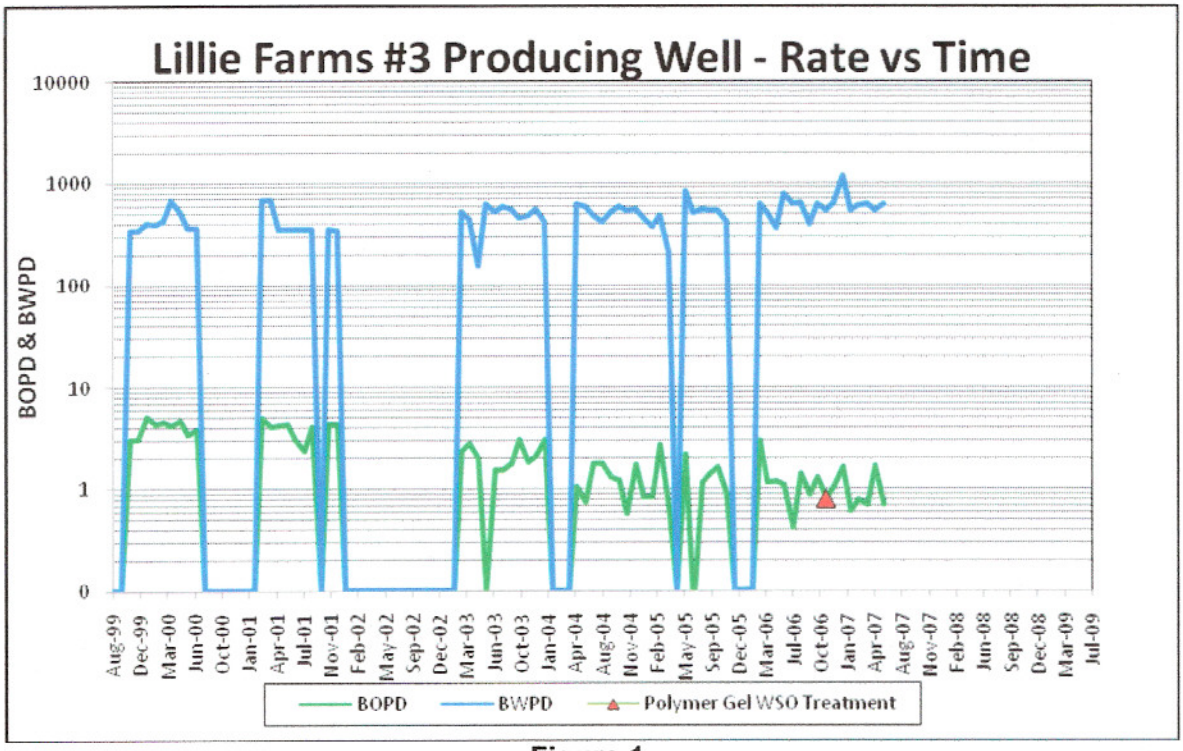

Figure 1.

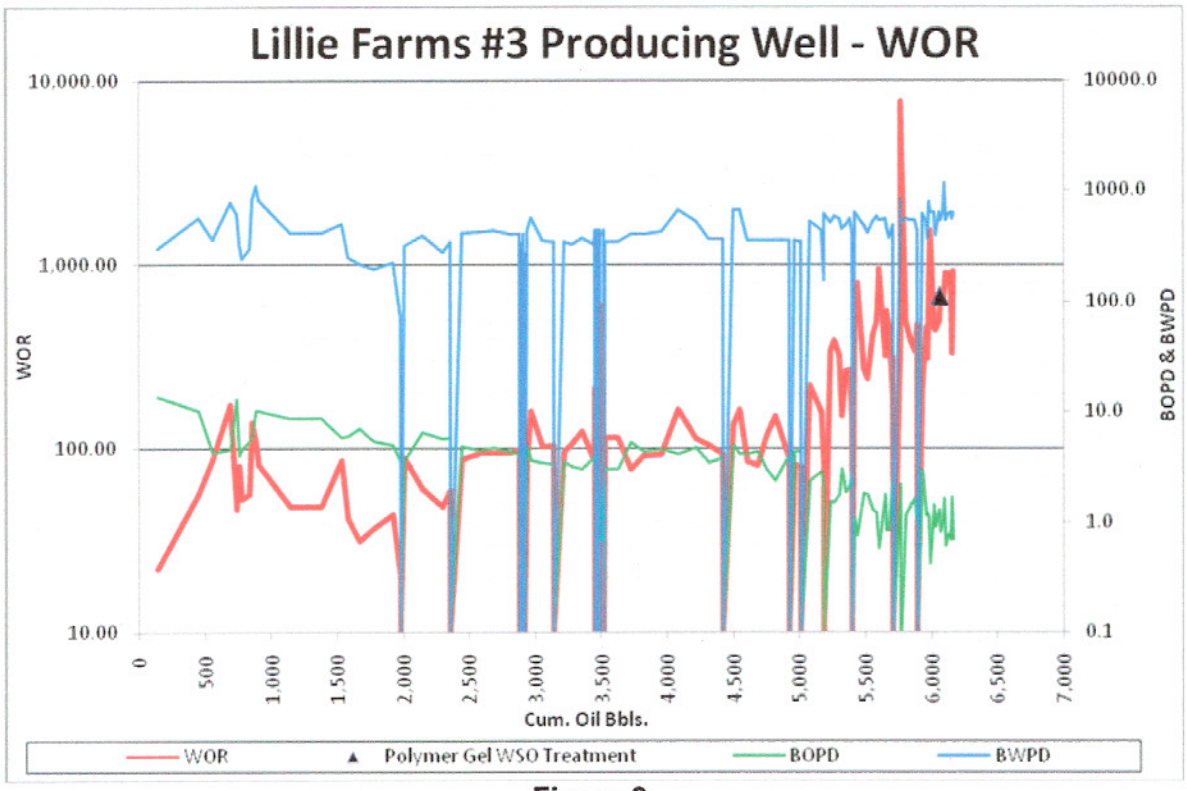

Figure 2.

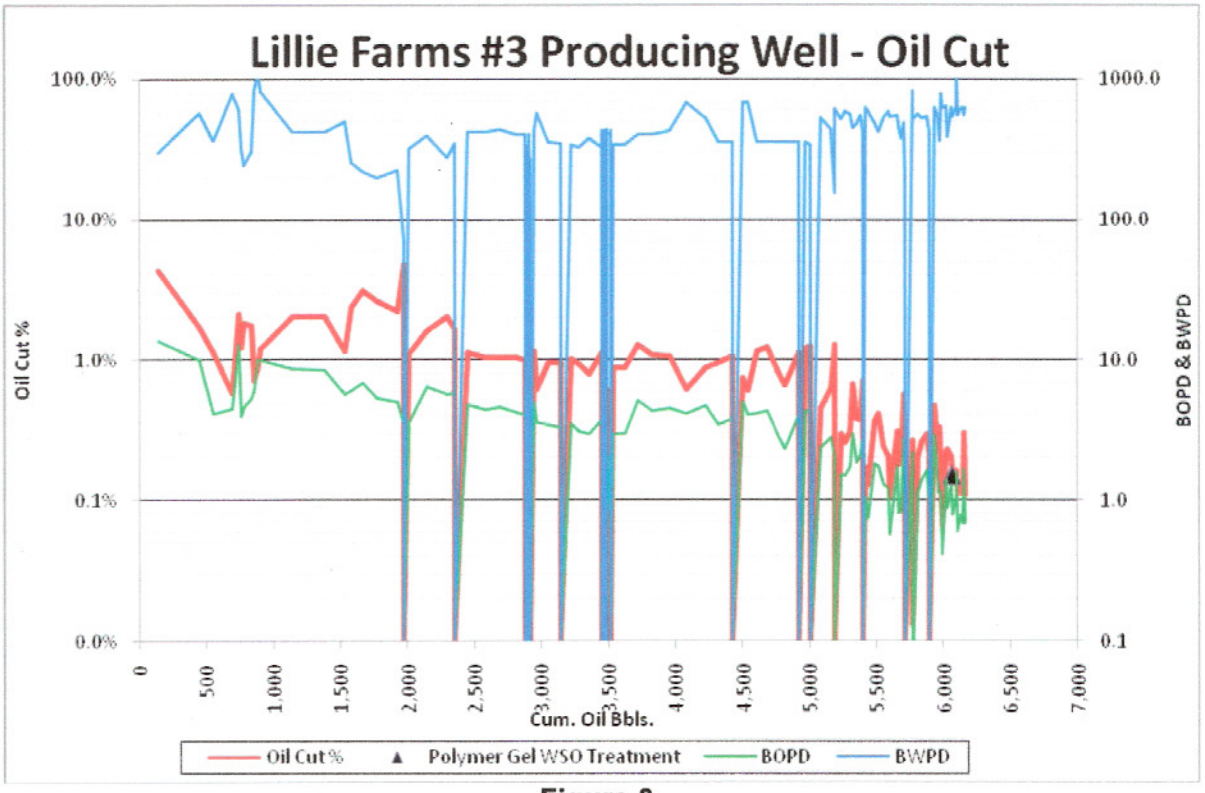

Figure 3.

Since the production data indicates that the treatment was not successful, a comparison was made between pre-treatment and post-treatment producing fluid levels to see if the PI for this well had been changed. Prior to the treatment, the producing fluid level in this well was 500 feet from surface. The producing fluid levels recorded after the treatment were as follows:

November 25, 2006 = 2,200 feet from surface

November 31, 2006 = 1,500 feet from surface

December 18, 2006 = 300 feet from surface

May 18, 2007 = 868 feet from surface

Given a constant static shut-in fluid level of 100 feet from surface, the pre-treatment PI was 3.2 BPD per psi, which means that the well had the capability of producing about 6,100 barrels of water per day at maximum draw-down. The post-treatment PI has ranged from 0.195 to 1.67 BPD per psi, which means the flow capacity has been reduced to the range of 1,750 to 3,200 barrels of water per day. This suggests that the polymer gel treatment has reduced the

water flow capacity by 48% to 71%. Although the well has been producing with more draw-down on the reservoir since the treatment was performed, the oil cut and WOR have not changed from pre-treatment values.

LESSONS LEARNED AND RECOMMENDATIONS

The reason that the results of this treatment did not meet the expectations may be related to the pressure observed during the job. Perhaps the treatment was ended too soon at too low of a pressure. Increasing pressure during the job is an indicator that flow through the fracture is being diminished as it becomes full of polymer gel. More water may have been shut off if the polymer gel had been more tightly "packed" into the fractures to provide for a more complete blockage and a greater reduction in flow capacity. The resulting reduced flow capacity may have enabled this well to be "pumped-off" to achieve maximum draw-down on the reservoir. The higher draw-down may have allowed for a significantly higher oil producing rate.

It is also possible that the 100 barrel water displacement volume was too large, and that the polymer gel solution was pushed to a position below the oil-water contact. If the polymer gel solution was displaced too far, a connection between the aquifer and the wellbore may have been re-established, which allowed for continued high water flow rate and resulting high fluid level.

It is not known why the oil cut percentage and WOR were not changed for the better, in spite of achieving more draw-down on the reservoir since the polymer gel treatment was placed. Perhaps there is not a sufficiently large volume of remaining and recoverable mobile oil in the lower permeability rock in the area surrounding this wellbore, which is possible since the well has never produced more than 5 BOPD. It is also possible that some of the polymer gel solution penetrated and damaged some of the oil-bearing pore spaces, and subsequently blocked the increased flow of oil into this wellbore that should have been realized under the more favorable draw-down conditions. If some of the oil-bearing pores have been damaged, then the well may be a candidate for some kind of stimulation treatment that will selectively re-

establish flow from these areas of the reservoir. Conversely, if there is not much remaining mobile oil left to recover, then the only way to improve well economics is to re-treat with polymer gel in an attempt to shut off more water.

While the treatment did not increase oil production, potential water volumes may well have decreased. The productivity index would indicate that the pre-treatment potential of 6100 BFD was decreased to about one-half of that volume. Because of the capacity of the production equipment on the well, maximum fluid volumes are restricted to a total of 650 BPD, well below the potential fluid volume for the well. This would represent a substantial reduction in the water volume. Additional well treatments will be necessary to determine the value of the technology for North Dakota water production problems. The subsurface geological conditions in this portion of North Dakota are obviously similar to the Central Kansas Uplift, but individual wells may have different characteristics. The well selection process for future treatments should reflect what was learned from the Lillie Farms #3 project, for example, a perforated wellbore with a lower productivity index and production equipment that can reasonably be expected to have the capability of moving the total fluid volume. The results, while not an economic success, offer enough encouragement to warrant support of additional treatments in order to determine if the technology can be adapted to North Dakota oilfields.