USING FOAMERS TO EXTEND THE LIFE OF THE LIQUID LOADING GAS WELLS

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ABSTRACT

The combination of continuous increase in worldwide brown-field activity and overall depletion of current gas fields has renewed focus on maximizing gas production from existing wells.
In most gas wells, water and/or condensate is produced along with gas. As gas wells mature, decreasing formation pressure and gas velocities gradually impair the well, resulting in a production decline due to the inability to lift these fluids. The artificial lift methods currently employed to deliquify gas wells are plunger lift, ESP, compression, and intermittent shut-in.

An alternative to the mechanical artificial lift methods is the use of "foamers".
This paper presents five case histories of successful foamer treatment utilizing both oil soluble and water soluble foamer applications.

INTRODUCTION

Foamers are surfactant based products that have both a hydrophilic head group and a hydrophobic group. As a result, surfactants alter surface properties such as surface tension and wetability. There are two kinds of foamers with respect to their solubility: water soluble and oil soluble. The water soluble foamers are used when the fluids produced by the gas well are mainly brine with very little condensate, and the oil soluble foamers are used when the gas well fluids are mainly condensate with < 50% brine. Foamers can be applied either by batch treatment or by continuous treatment. These products are used to increase production, stabilize flow, and reduce fluctuations in the gas production of the well.

CANDIDATE WELL SELECTION

In order to select a well that will successfully respond to treatment with foamers, a series of steps need to take place to better evaluate candidate wells. This includes flow modeling to confirm that the well is loaded, foam column testing with field fluids and a review of the production history of the candidate well.

FLOW MODELING

The proprietary model that is used incorporates the effects of lowering the surface tension and densities.
In the current program, the modified Turner equation[1] presented by Coleman[2] is used. This computer model incorporates the effect of chemicals on the surface tension and fluid density of well bore fluids. Calculations are made to determine the gas superficial velocity and minimum velocity at which loading begins as a function of the concentration of different chemicals at the wellhead, tailpipe and perforations. Whenever the gas superficial velocity is above the velocity at which liquid loading occurs, this implies that liquid will not accumulate at this point. When actual gas velocity is greater than the theoretical velocity no loading occurs in the perforations, tailpipe and at the well head and foamer is not needed. In wells which the superficial gas velocity is below the theoretical velocity, loading occurs. The foamer reduces the theoretical velocity at which loading occurs relative to the superficial gas velocity, helping to remove the liquids from the well.

FOAM COLUMN TESTING

Field fluids from candidate wells are initially screened using a foam column test to further assist with the foamer selection. The test set-up was adapted from the Bikermann method[3] to test the foaming tendency of each chemical. A schematic diagram of the test equipment is presented in Figure 1. This equipment includes: a jacketed test column with a glass frit, a gas supply or air pump, a flow meter, a water circulator, a beaker for collecting unloaded fluids, a graduated cylinder, and a balance[4]. For on-site evaluation, the test set-up did not use the water circulator. The on-site testing was conducted at ambient temperature, 25 ºC (77 ºF), to minimize possible evaporation of fluids, which could occur if higher temperatures were utilized.

One hundred (100) mL of liquid of fresh well fluid were weighed to record the fluid weight and volume. This fluid was then added to the fritted foam column, and a gas sparge was initiated. A control test was conducted at a fixed rate of gas flow through the column. After which, concentration profile for the foamer was performed, and the weight of the lifted foam was recorded to establish a percent recovery based on weight percent.

CANDIDATE WELL PRODUCTION HISTORY REVIEW

The current production history of the candidate well prior to foamer treatment is reviewed and the production baseline is established before treatment with the foamer. When the production history indicates the well is slugging or dieing a foamer treatment is appropriate, provided the foamer(s) performed well in the foam column tests using well fluids. The next step will be to field trial the foamer. As the foamer is being applied, production data is closely monitored. The performance with the foamer is evaluated and optimized along the way.

CASE HISTORY ONE (OIL CONDENSATE FOAMER)

Problem

A customer in South Texas had a particular gas well that loaded with fluids containing 65 percent condensate. Although the well pressure was sufficient to periodically unload the well as shown in Figure 2, the cyclic nature of the production clearly showed the well was producing primarily under loaded conditions. Because of the well's slim-hole type of completion, an electric submersible pump, rod pump, or plunger were not considered economically-viable options. To mitigate liquid loading and improve gas production, the operator placed the well on a 24-hour "On" /24-hour "Off" cycle, using a mechanical "intermitter". This cycle time was determined to be the optimal "ON-OFF" regime, since the well would naturally load up with fluids after one and a half days following a 24-hour shut-in period. Figure 3 shows the production of the same well with intermitter-cycle control. The operator believed that deliquification of the well using chemical foamers would provide the most cost-effective solution. However, some conventional, water-based foamers applied in this field previously and were not successful unloading gas wells with condensate levels greater than 50 percent.

Solution

As a result of studying chemical deliquification of gas wells with high ratios of condensate (greater than 60 percent), an oil soluble foamer was developed and patented that addresses this particular deliquification challenge. After modeling this well it was concluded this well was a suitable candidate for the new oil soluble foamer that was applied to the well continuously via capillary injection tubing.

Results and Benefits

Figure 4 shows the new gas production rate for the well treated with oil soluble foamer. Continuous application of this oil-soluble product at a concentration of 10,000 ppm produced an average of 900 Msfcd for 11 consecutive days. At this point in the trial, the foamer concentration was reduced below its effective dose rate, and the well began to load again. The intermitter was then turned back on to control pressure build-up for 24 hours following the shut-in period. Gas production over the 11-day period with the foamer applied was 9,900 Mscf, but without foamer, the well with only intermitter operation produced 900 Msfcd, and for only for one and a half days before it was shut off again to rebuild pressure. These results demonstrate that for this trial, the well produced 83 percent more gas over 11 days when the oil soluble foamer was applied. Figure 5 shows results of cumulative condensate and water production over the 12-day trial period, with one day accounting for the "Off" period. A 33 percent increase in condensate fluids resulted from application of the oil condensate foamer. The gain in condensate represents additional well revenue, over and above that gained from increased gas production. Based on the natural gas and oil prices at the time of the trial, over the 12-period, the incremental gas revenue resulting from the oil soluble foamer application was approximately $16,000, compared to $8,800 without foamer treatment. The increase in condensate revenue resulting from the foamer treatment was estimated to be $18,600, compared to $14,000 without foamer.

CASE HISTORY TWO (OIL SOLUBLE FOAMER)

Problem

A customer in central Wyoming had a gas well that was liquid loaded. Several factors were taken into consideration when possible treatments for the well were being discussed with the customer. For example, when flowing, produced fluids consisted of 80% condensate and experienced a paraffin problem. A paraffin inhibitor had been applied via capillary injection previously but with little success. The customer decided to pull the capillary tubing, but it broke and became stuck, thus limiting treatment options. Due to the significant amount of condensate generated by this well, it was determent that traditional water-soluble foamers would not be applicable in this well.

Solution

Successful laboratory tests results with the oil soluble foamer were discussed with the operator, who approved a batch treated with the oil condensate foamer in this well. Following the foamer treatment the well was shut-in for three days to build pressure and then produced for four days before it was treated again with foamer.

Results and Benefits

Immediately after batch treating, the dead well was revived and production increased to 300 Mscfd and 75 BOPD. Due to the significant increase in oil production, the customer had to expend the storage capacity of the surface equipment to accommodate the additional condensate production. Batch treatment once per week with the oil soluble foamer resulted in a revenue increase for the customer of about $10,000 per day (based on spot prices at the time of the trial). As a result of continuing the application of the oil soluble foamer, the well continues to produce approximately 300 Mscfd and 75 BOPD.

CASE HISTORY THREE (WATER SOLUBLE FOAMER)

Problem

A major operator in East Texas was experiencing liquid loading problems in a gas well, resulting in severely diminished gas production. Using well completion and production information, the well was modeled to confirm that the well was experiencing liquid loading. After confirming that the well was liquid loaded, a trial with this product was approved by the customer.

Solution

The operator installed capillary injection tubing in the well to facilitate a continuous foamer treatment. The customer provided the production data that was collected during the field trial in their production database. The gas production rate was monitored prior to initiating treatment with water soluble foamer to establish the baseline for comparison. To start the trial, the well was shut in for 48 hours while foamer was continuously injected through the capillary tubing. The well was then brought back on production while maintaining the continuous chemical application. Production was monitored for six days after the well was brought back online.

Results and Benefits

The gas production rate from the test well is shown in Figure 6. A substantial gas production increase was realized. The first day the well was back online gas production reached 750 Mscfd and gradually declined to 394 Mscfd by the sixth day of the test. At this point the test was completed. The 6-day average gas production during the application of the foamer product was 504 Mscfd. This is a significant production improvement relative to the 94 Mscfd production rate observed prior to addition of the foamer. For the trial period, the incremental average daily gas production was 410 Mscfd, and the incremental gas revenue generated during the field trial was approximately $2,300/day or $13,900 total for the 6-day test period based on the Henry Hub spot market gas price of $5.65/Mscf.

CASE HISTORY FOUR (WATER SOLUBLE FOAMER)

Problem

An East Texas producer was experiencing liquid loading and associated production losses in several natural gas wells. A standard liquid foamer treatment was used on other wells in the field. While capable of unloading the wells, it was not providing the desired level of performance. Because of this, the operator was interested in evaluating a new foamer which was designed to be more tolerant of condensate than the incumbent product.

Solution

Using well completion and production information, the well was modeled to confirm that the well was experiencing liquid loading. Once liquid loading was confirmed, the operator installed capillary injection tubing into the well to facilitate the continuous foamer treatment. For comparison purposes, the incumbent product was first applied to establish a gas production baseline with the incumbent foamer. Once the incumbent field trial was completed and the production rate was establish then the new foamer was applied and the dose rate optimized. Upon completion of the new foamer trial period, the incumbent foamer treatment was reinitiated to further validate the gas production rate increase realized when using the new foamer.

Results and Benefits

At comparable injection rate to the incumbent foamer the new foamer resulted in a substantial production increase. In an optimization test during the injection of the new foamer the injection rate was decreased 40%. Within 24 hours of this injection rate decrease, gas production noticeably declined. As a result, the chemical injection rate was returned to the original injection rate and within 24 hours the gas production rate rebounded. Upon completion of the new foamer trial, injection of incumbent foamer was initiated at the same rate in order to confirm the greater unloading efficiency of the new foamer. Gas production noticeably declined to 184 Mscfd, or very near the pre-trial level. The 17-day average gas production prior to the injection of the new foamer with the incumbent product was 187 Mscfd. In comparison, production rates during the new foamer injection averaged 247 Mscfd for the 16 days when the new foamer was injected. The average gas production stabilized at 275 Mscfd for the last six days of the field trial. The incremental average daily gas production at the stabilized production rate was 88 Mscfd and the incremental gas revenue generated during this period was approximately $651/day based on the Henry Hub Spot Market gas price of $7.40/Mscf. On the basis of this trial, the operator began a systematic field-wide changeover to the new foamer. Figure 7 illustrates the results of this trial.

CASE HISTORY FIVE (WATER SOLUBLE FOAMER)

Problem

An East Texas producer suspected that one of his gas wells was liquid loaded. This well was 9860 ft in depth, and was equipped with 2 3/8-in production tubing and 5 ½-in casing. It was producing 1.59 bbl of 55° API gravity condensate/day, 76.21 bbl of water/day, and 126 Mscfd gas when the G-10 test was performed on this well on September 1, 2007. The flowing wellhead pressure was 200 psig. This well had never been treated with foamer prior to the field trial.

Solution

The producer provided all the requested well information and current production data that were needed to model the well to assure that the well was a good candidate for foamer treatment. After confirming the well was experiencing liquid loading with the model, it was decided that the well would be batch treated with the new water soluble foamer.

The field trial was initiated on August 12, 2007 and was completed on August 26, 2007. The final results of the field trial were documented, and the results of the field trial were shared with the Operator.

Results and Benefits

This gas well was batch treated with 10 gallons of new water soluble foamer that was diluted in 3 bbl of 1% KCl and was then shut in 24 hours. Gas production averaged 116 Mscfd during the previous 11 days before treatment. After treatment gas production averaged 141 Mscfd over the 14 days after the treatment. Production peaked at 161 Mscfd on the second day after treatment. The net incremental gas for the 14 days after treatment was 696 Mscf, valued at $3670 based on a spot market gas price of $7.40/Mscf.

This well was treated with another foamer fifteen days after the new water soluble foamer treatment. The net incremental gas production for eleven days following the other foamer treatment was approximately equal to the untreated production rate before treating with new water soluble foamer. A production spike of 137 Mcfd was realized the second day after treatment, 24 Mcfd less than the peak gas production rate with new water soluble foamer. Zero incremental revenue was realized over the 11 days following the other foamer treatment.

REFERENCES

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3. J.J. Bikerman, Trans. Faraday Soc., 34:634 (1938)
4. Orta, D.; Ramachandran, S.; Yang, J.; Fosdick, M.; Salma, T.; Long, J.; Blanchard, J.;-- Baker Petrolite Corp. Allocorn, A.; Atkins, C.; Salinas, O.—Shell Exploration and Production. “A Novel Foamer for Deliquification of Condensate-Loaded Wells”, SPE 107980-PP Presented at 2007 SPE Rocky Mountain Oil & Gas Technology Symposium held in Denver, Colorado, USA, 16-18 April 2007

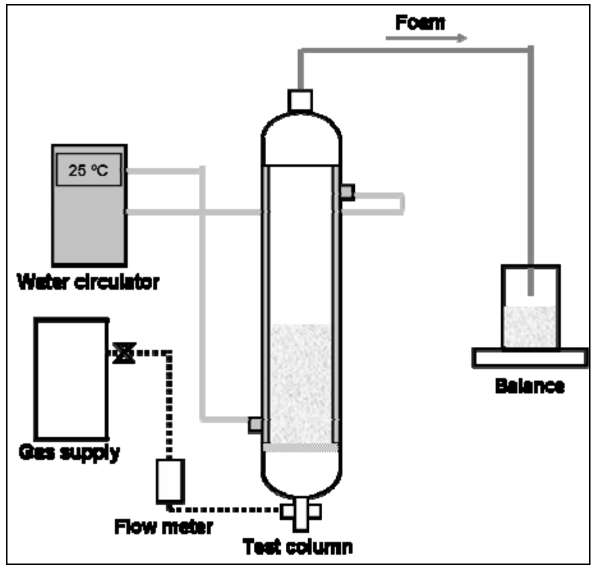

Figure 1 - Schematic Diagram of Foam Performance Test Equipment

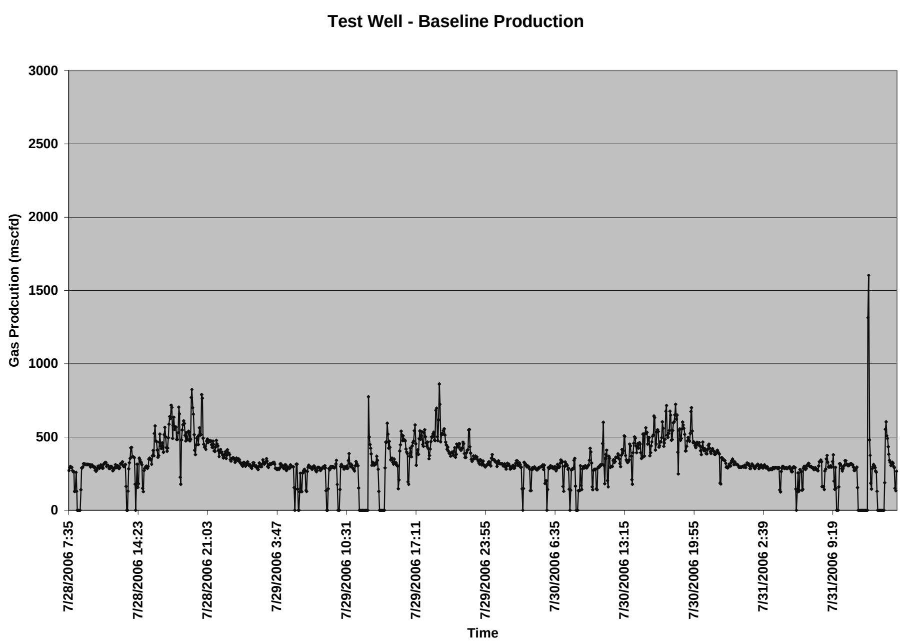

Figure 2 - Gas Production of Well Under Loading Conditions

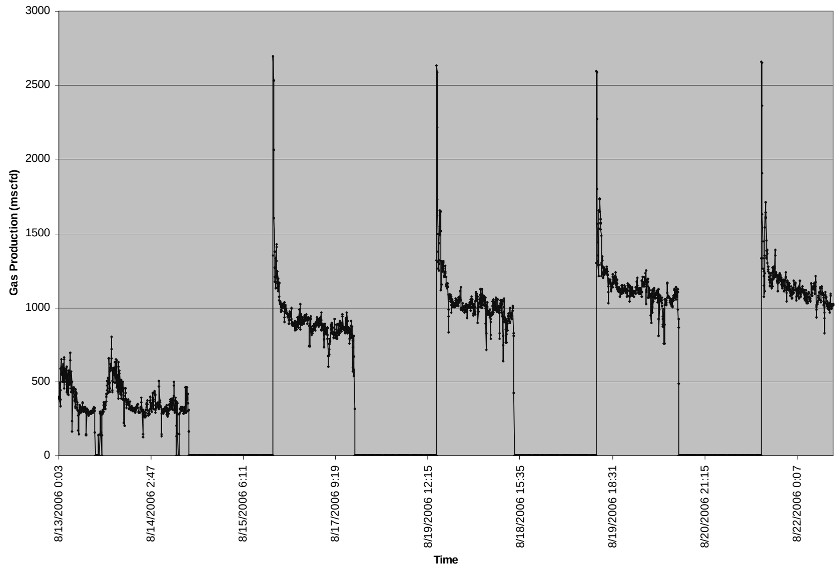

Figure 3 - Gas Production from Cycle-Intermitter Control

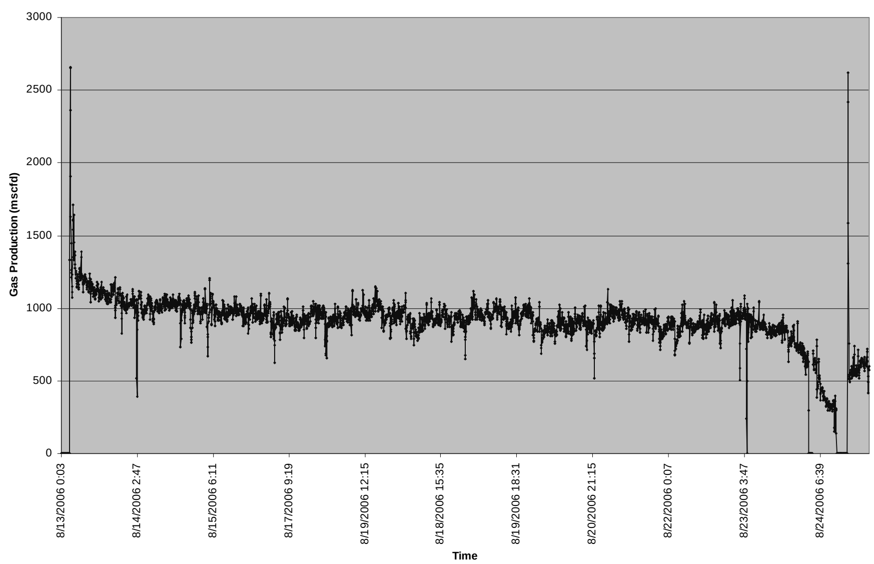

Figure 4 - Gas Production Increases from Oil Condensate Foamer Application

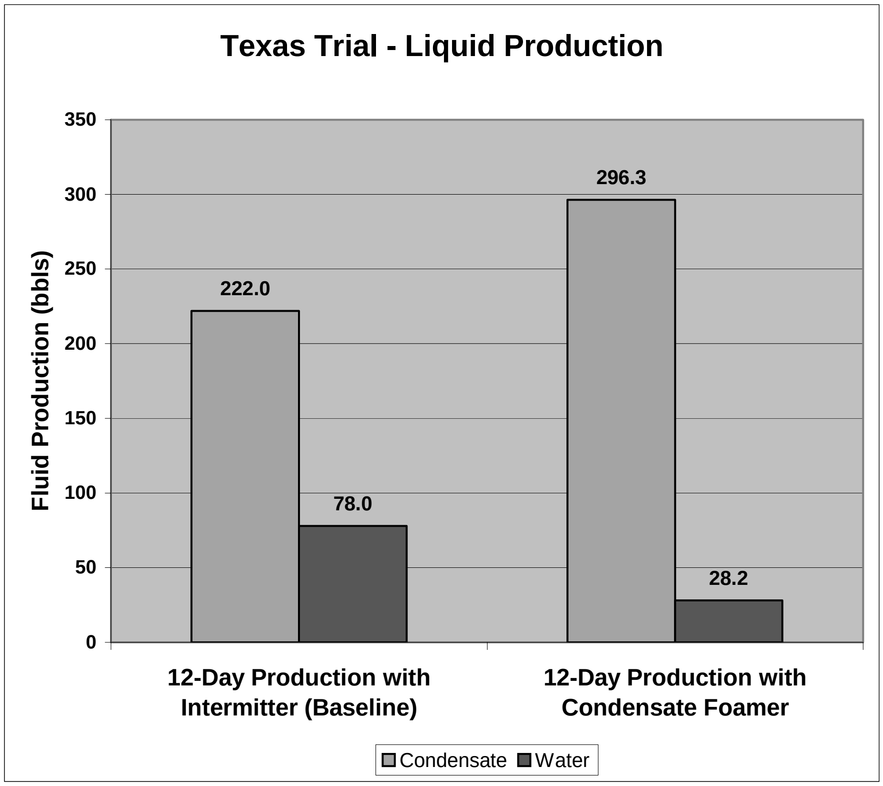

Figure 5 - Total Condensate and Water Production With and Without Oil-Soluble Foamer

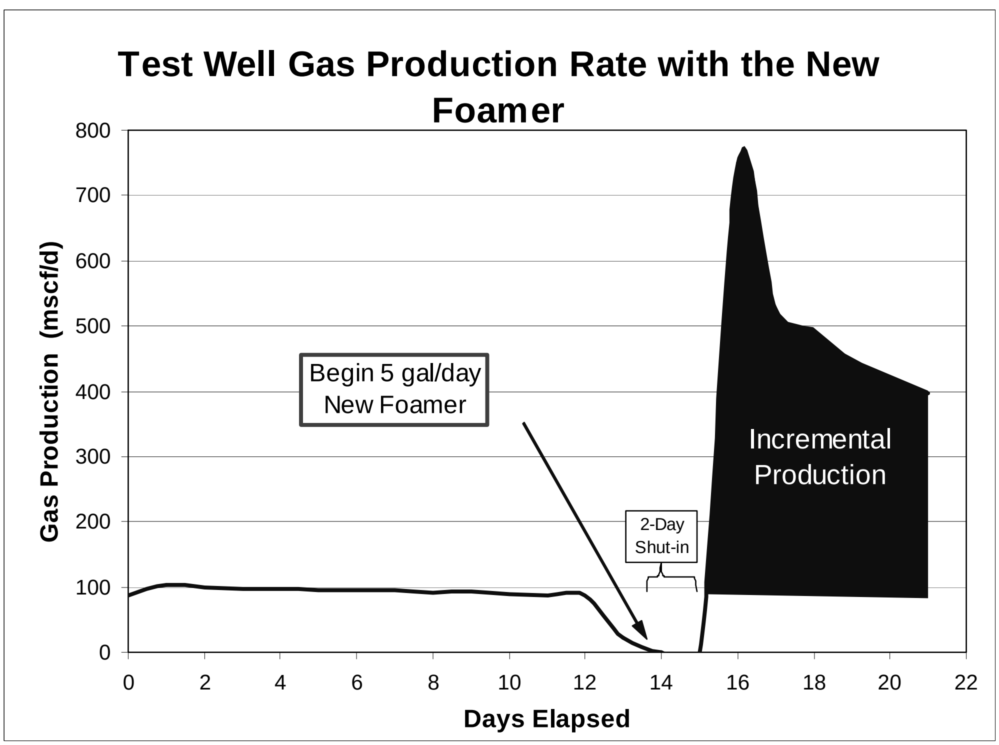

Figure 6 - Incremental Gas Production Resulting from Continuous Injection of New Foamer

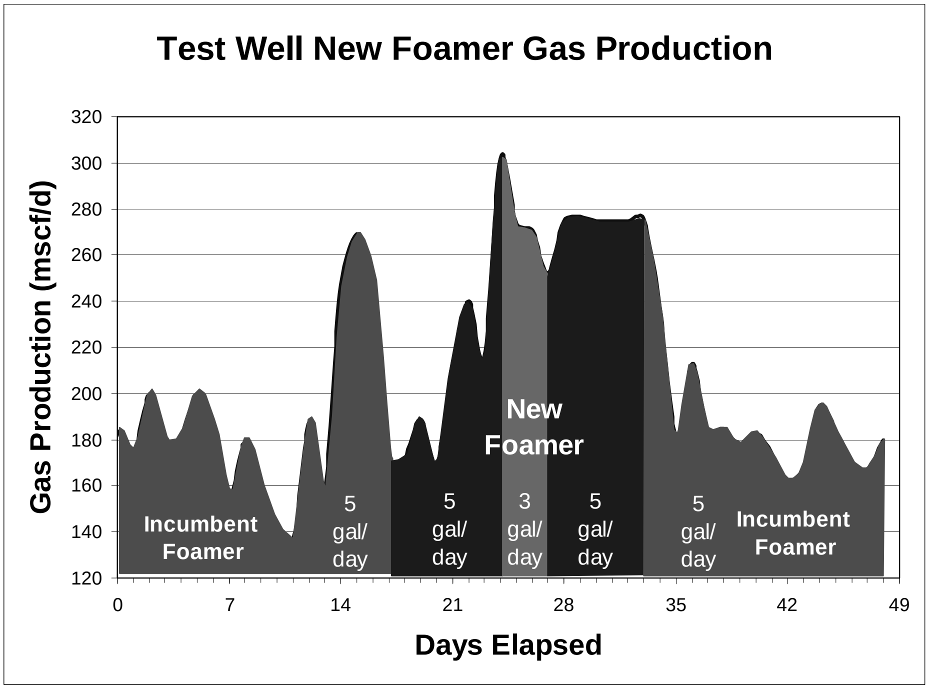

Figure 7 - Gas Production Increases with Continuous Injection of the New Foamer

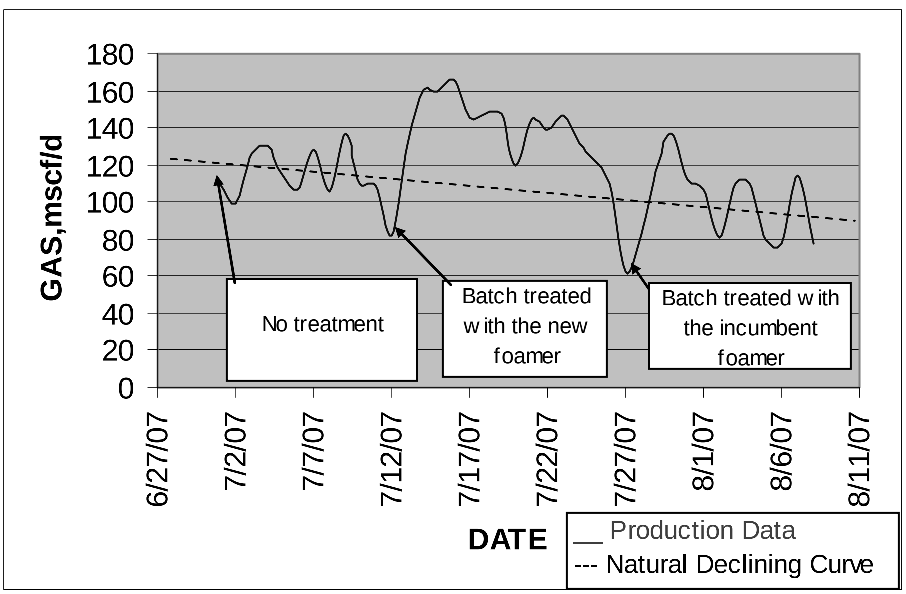

Figure 8 - Gas Production Increases Resulting from Batch Treatment of the New Foamer