Successful Acid Stimulation of San Andres

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ABSTRACT

San Andres producers in several areas in Gaines County, Texas are limited on stimulation injection rates due to the proximity of potential water producing intervals. The San Andres is a dirty dolomite formation with a bottomhole temperature of approximately 135F. Usage of acid to stimulate the formation is desirable, but given the low injection rate, diversion and penetration of the acid into the formation are difficult to accomplish. Prior treatments using rock salt for diversion resulted in most of the salt falling into the rat-hole. Recently, success has been achieved utilizing a viscoelastic acid diversion system and a chemically retarded acid system pumped in alternate stages. Injection rates have been held to 3 BPM or less, with pressure increases from diversion being observed. Initial production responses have been from 2 to 7 times more oil and 2 to 5 times water.

Three cases will be presented including the historical information from present and past treatments and production data. All of the treatments were performed on the San Andres formation in Gaines County from 5400 to 5800 in these cases. Treatments were targeted to the formation in separate intervals. This discussion will cover all these areas and data.

INTRODUCTION

The San Andres formation in Gaines County is primarily a dolomite with anhydrite. The dolomite portion is 77% to 92% and the anhydrite 3% to 20% of the composition.[1] **Table 1** illustrates some typical mineralogical analyses. The acid solubility is 78% to 92%. The average bottomhole static temperature is 135 degrees °F in this area and the average bottomhole pressure is about 1200 psi. The formation typically has a fracture gradient of 0.70 psi/ft. The average porosity and gas permeability are 13.5% and 10 mD respectively, **Table 2**.[1] The average water saturation of this formation is 40%. The target production intervals are around 5500 ft. The area is under an active waterflood and typically only a small acid job to breakdown perforations is required to affect an economic producer.

Forming in the Permian Period of the Paleozoic Era the San Andres resulted from variations in the depositional environment.[2] "The typical San Andres reservoir rock is a heterogeneous carbonate characterized by extreme vertical and lateral variation in porosity and permeability development. These reservoirs can be visualized as a series of porous-permeable zones developed within a gross reservoir section that often may be hundreds of feet thick".[3] **Figure 1** is a representation of a typical openhole log section across the San Andres in this area.

Production of water from this formation is a concern due to the close proximity of water zones above and below oil producing zones. An Additional problem is the presence of an active waterflood. Because of the potential of increasing water production as a result of any stimulation use of low pump rates of 3-4 BPM is essential to control vertical coverage and avoid communication between zones. Penetration into the reservoir is what will yield successful results.

The wells discussed in this paper are ones that have been stimulated in the past with small acid jobs at low rates with various methods of diversion that resulted in good initial production rates but declined at a steeper than typical rate for the reservoir characteristics of the area. Because each subsequent acid treatment leaves behind an increase in effective surface area each following acid treatment should be pumped faster and/or use a larger volume in order to effect a deeper penetration.

Since increased rate is out of the question and larger acid jobs become increasingly costly change to a retarded acid system and more effective diversion that takes place outside of the casing is a good choice to solve the problem. **Figure 2** relates the reactivity of a chemically retarded hydrochloric acid system to that of neat hydrochloric acid at 250°F. From this graph it can be seen that in a very short time neat acid is completely spent and therefore is unable to travel very far into the reservoir as a reactive fluid. Typical diverters such as rock salt, ballsealers and other solids are effective where a sufficient rate is used to effectively bridge or plug perforations. Slow pump rates allow for more rapid falling rates of these materials and in the case of salt the increased contact time in the carrying solution may allow more of the material to be dissolved, which in either case reduces the amounts of materials actually getting to perforations. Again since rate is an issue, using a viscoelastic acid diverter system, which builds viscosity as it spends has no such rate dependence. **Figure 3** shows the effect of spending viscoelastic acid systems and the resulting change in viscosity. This significant increase in viscosity under a low shear environment, such as a low rate matrix treatment, will provide the increase drag on the fluid and subsequent creation of diversion. Significant pressure responses typically experienced using the aforementioned diversion methods will not be observed; only slight increases may be noted during a treatment.

CASE STUDY

Over the past year, 3 treatments combining a viscoelastic acid diversion system and a chemically retarded acid system have been performed in Gaines County, Texas. These treatments have resulted in improved production declines more characteristic of the area without excessive increases in water production. The zones are individually treated in two stages using a packer retrievable bridge plug for isolation. Slight pressure increases are noted during the treatments.

Well #1

In the first stimulation of this well the perforations were broke down in April 2003 (5,697’-5,736’) with produced water. When swabbed the oil cut was 100%. Also, in that year the interval of 5,400’ to 5,684’ was acidized with 2500 gallons of 20% hydrochloric acid using straddle packers. The perforations were broke up into 5 sets and treated at an average injection rate of 0.9 BPM. The production was 215 BOPD, 169 BWPD, & 40 MCFD.

In December 2005 the interval of 5,400’ to 5,736’ was treated in 4 stages with a total of 4,500 gallons of 20% Hydrochloric acid. An average rate of 3.0 BPM was achieved with 1,400 Lbs. of rock salt used in the diversion process. The production after this treatment was 70 BOPD, 308 BWPD, and 24 MCFD. In less than thirty days production had dropped to a level of 23 BOPD, 139 BWPD, and 5 MCFD (loss of 67%). Immediately after the treatment 85’ of salt fill was observed in the casing and calculations determined this to be approximately 400 to 500 pounds. With approximately one third of the graded rock salt being about three eights of an inch in diameter these particles would be falling at about 177 feet per minute in a fluid that is moving at approximately 126 feet per minute and this could account for the fill. Further calculations of the dissolving power of the 20% hydrochloric acid, in which the salt was dropped, during the treatment determined that approximately 400 pounds of the salt would have been lost prior to reaching the perforations. Therefore only about 500 pounds of the originally used rock salt could have actually created any diversion. Incomplete coverage of the zone can be concluded.

The new treatment in June of 2007 consisted of two stages. Perforated intervals treated by each stage are listed in **Table 3**. The sequence of fluid stages and the volumes used are listed in **Table 4**. Treatment rate for the two stages ranged from 1 to 3 BPM with surface treating pressures ranging from 600 to 1,600 psi, **Figure 4**. Production responses of the various treatments to date are illustrated in **Figure 5**. It can be seen in this graph that although increases in production were obtained after each acid treatment only after the last one has the oil production stabilized at a much shallower decline rate.

Well #2

The second well was initially perforated at 5,453’ to 5,702’ and was acidized in December, 2001. 2,300 gallons of 20% hydrochloric acid was used with straddle packers using 11 settings. The treatment was pumped at an average of 0.5 BPM.

In June of 2003 the interval of 5,412’ to 5,757’ was treated with 600 gallons of 20% hydrochloric acid with packer isolation (4 sets). An average rate of 0.3 BPM was pumped.

In December of 2005 5,412’ to 5,757’ was treated again. This time larger amount of 20% hydrochloric acid (4700 gallons) was used with 1,400 pounds of rock salt, pumped at an average of 3.0 BPM. After the treatment 22’ of salt fill was left in casing which is approximately 100 to 125 pounds. The 20% hydrochloric acid dissolved about 400 pounds of the rock salt, which means that only 875 to 900 pounds of the 1,400 pounds actually acted as a diverter. After the treatment a production response of 62 BOPD, 275 BWPD and 15 MCFD was observed. In less than thirty days production had declined to 38 BOPD, 151 BWPD, and 7 MCFD (a loss of 55%). Incomplete coverage of the zone can be concluded from the information above.

The last treatment on this well was a two stage job similar to well #1 above. The first stage treated the interval of 5,662’ to 5,744’ with 1,950 gallons of a retarded 20% hydrochloric acid and 1,000 gallons of a viscoelastic 20% hydrochloric acid system. It was pumped at an average rate of 3.0 BPM and treated at an average surface treating pressure of 1,355 psi. The second stage treated the interval of 5,415’ to 5,512’ with 1,825 gallons of the retarded hydrochloric acid and 925 gallons of the viscoelastic hydrochloric acid. This interval treated at an average surface pressure of 1,140 psi and at average rate of 3.0 BPM. The treatment rates and pressures for both stages are illustrated in **Figure 6**. Production following the treatment was 48 BOPD, 15 MCFD and 249 BWPD, **Figure 7**. After three months production is 36 BOPD, 9 MCFD and 260 BWPD and seems to be stable at these rates.

Well #3

The third well was initially perforated and acidized in December, 2001, also. 1,500 gallons of 20% hydrochloric acid was used with straddle packers. The treatment was pumped at an average of 0.5 BPM. Production after this treatment was 210 BOPD, 38 MCFD and 131 BWPD which declined to 23 BOPD in June of 2003.

In July of 2003 more perforations were added and the entire interval was treated with 2,000 gallons of 20% hydrochloric acid with packer isolation. An average rate of 0.3 BPM was pumped. The production response after this workover was 39 BOPD, 17 MCFD and 273 BWPD. Decline was shallower reaching 17 BOPD production level in October of 2007.

In November of 2007 this well was treated similar to the previous two, using two stages with isolation by a packer and a retrievable bridge plug. The first stage treated the interval of 5,700’ to 5,760’ with 2,745 gallon of a retarded 20% hydrochloric acid system and 1,600 gallons of a viscoelastic 20% hydrochloric acid system. 3.0 BPM was attained as an average rate with an average surface treating pressure of 1,261 psi.

In the second stage two intervals are treated, the original perforations at 5450’ to 5550’ and new perforations at 5,600’-5, 610’. The treatment consisted of 2,330 gallons of a retarded 20% hydrochloric acid system and 925 gallons of a viscoelastic 20% hydrochloric acid system. An average rate of 3 BPM was pumped at an average surface treating pressure of 926 psi. as before **Figure 8** illustrates the rates and pressures of this last workover. **Figure 9**, shows how the production has responded. Since this well was treated in November of last year only a limited amount of production data is available, but indications are that production has been improved to 23 BOPD, 8 MCFD and 394 BWPD.

CONCLUSIONS

1.) Low rate acid treatments using solids for diversion are ineffective and inefficient. By using a viscoelastic acid system for diversion and pumping at low rates to control zonal coverage a positive effect on production may be achieved.
2.) Use of retarded acids systems gives better production response than that of an acid with no reactivity control.
3.) Proper execution of matrix acid treatments on carbonates where increased water production is a concern improves the probability of success.

ACKNOWLEDGEMENTS

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2.) Black, Harold N. and Stubbs, Bruce A.: “A Case Study – Evaluation of San Andres Stimulation Results,” paper SPE 5649 presented at 50th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, Dallas, Texas, Sept. 28- Oct. 1, 1975.
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Table 1 Typical San Andres Mineralogical Composition				
Minerals	**Composition, %**			
	Depth, feet			
	5622	**5655**	**5687**	**5709**
Dolomite ($CaMg[CO_3]_2$)	77	90	90	92
Anhydrite ($CaSO_4$)	20	3	5	7
Gypsum ($CaSO_4$ + 2 H_2O)	nd	nd	nd	nd
Quartz (SiO_2)	2	3	3	trace
Kaolinite	nd	nd	trace	nd
Mica + Illite	nd	nd	trace	nd
Mixed-Layer Illite$_{(>90)}$/Smectite$_{(<10)}$	nd	3	trace	nd
Totals	100	100	100	100
SOLUBILITY TESTING RESULTS				
15% Hydrochloric Acid Solubility (%)	78.2	91.8	86.9	87.7
Soluble Iron Content (%)	0.03	0.01	0.01	0.01

Table 2 Typical Reservoir Parameters for San Andres		
Depth, feet	**Gas Permeability, mD**	**Porosity, %**
5622	1.62	10.9
5655	0.81	12.9
5687	6.09	14.9
5709	30.1	15.5

Table 3 Perforated Intervals Treated			
Stage	**Well No.**		
	1	**2**	**3**
	Depths, feet		
1	5598 - 5736	5662 - 5744	5700 - 5760
2	5400 - 5498	5415 - 5512	5600 - 5610

Table 4 Treatment Schedules			
Fluid Description	**Fluid Volumes, gallons**		
	Well		
	1	**2**	**3**
FIRST STAGE			
Chemically Retarded 20% Hydrochloric Acid	300	300	300
Viscoelastic 20% Hydrochloric Acid Diversion System	250	250	250
Chemically Retarded 20% Hydrochloric Acid	400	450	450
Viscoelastic 20% Hydrochloric Acid Diversion System	325	325	325
Chemically Retarded 20% Hydrochloric Acid	450	550	550
Viscoelastic 20% Hydrochloric Acid Diversion System	400	425	425
Chemically Retarded 20% Hydrochloric Acid	500	650	650
Viscoelastic 20% Hydrochloric Acid Diversion System	---	---	600
Chemically Retarded 20% Hydrochloric Acid	---	---	800
Flush and Overflush	2500	2500	2500
SECOND STAGE			
Chemically Retarded 20% Hydrochloric Acid	300	250	250
Viscoelastic 20% Hydrochloric Acid Diversion System	250	225	225
Chemically Retarded 20% Hydrochloric Acid	400	425	425
Viscoelastic 20% Hydrochloric Acid Diversion System	325	300	300
Chemically Retarded 20% Hydrochloric Acid	450	525	525
Viscoelastic 20% Hydrochloric Acid Diversion System	400	400	400
Chemically Retarded 20% Hydrochloric Acid	500	625	625
Flush and Overflush	2500	2500	2500

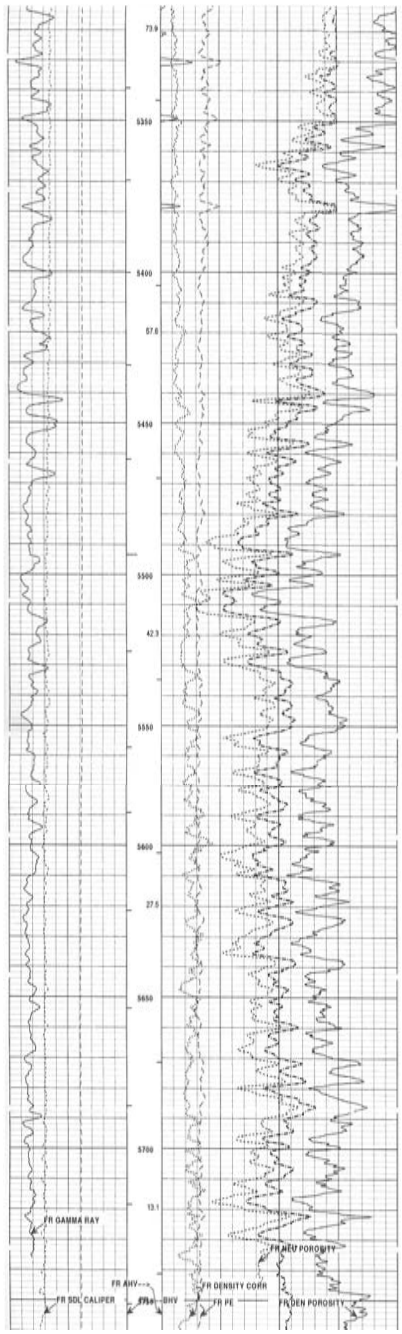

Figure 1 – Typical Openhole Log Section Across San Andres

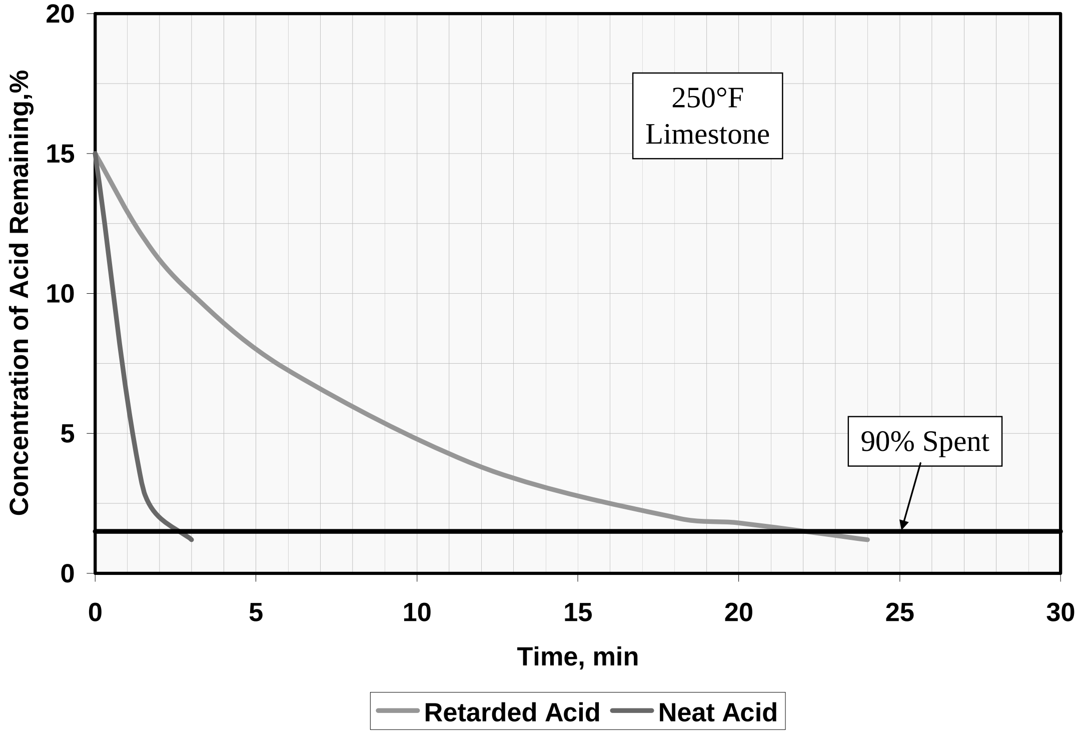

Figure 2 – Reactivity of Chemically Retarded Acid

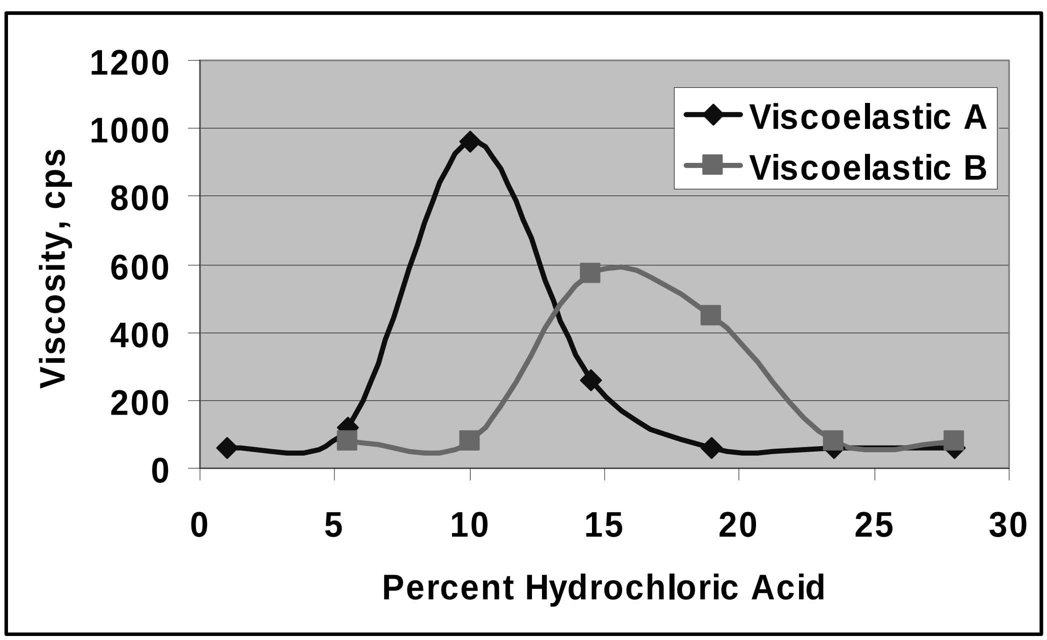

Figure 3 – Viscoelastic Acid Diversion System Viscosity Profiles with Spending

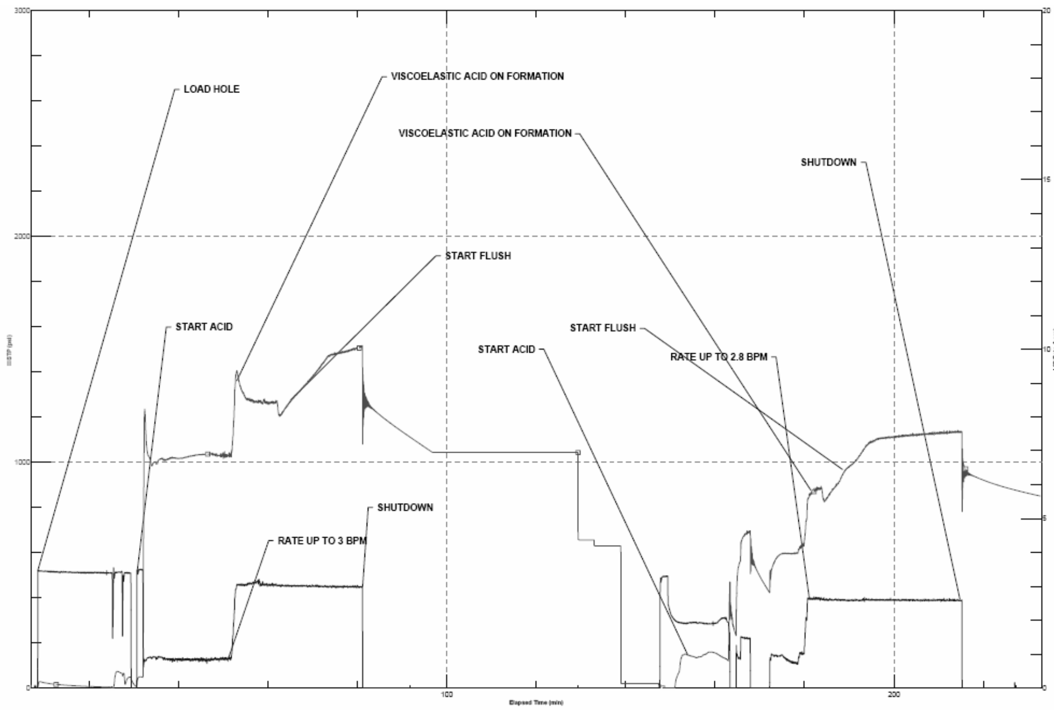

Figure 4 – Rate & Pressure Chart for Treatment of Well No.1

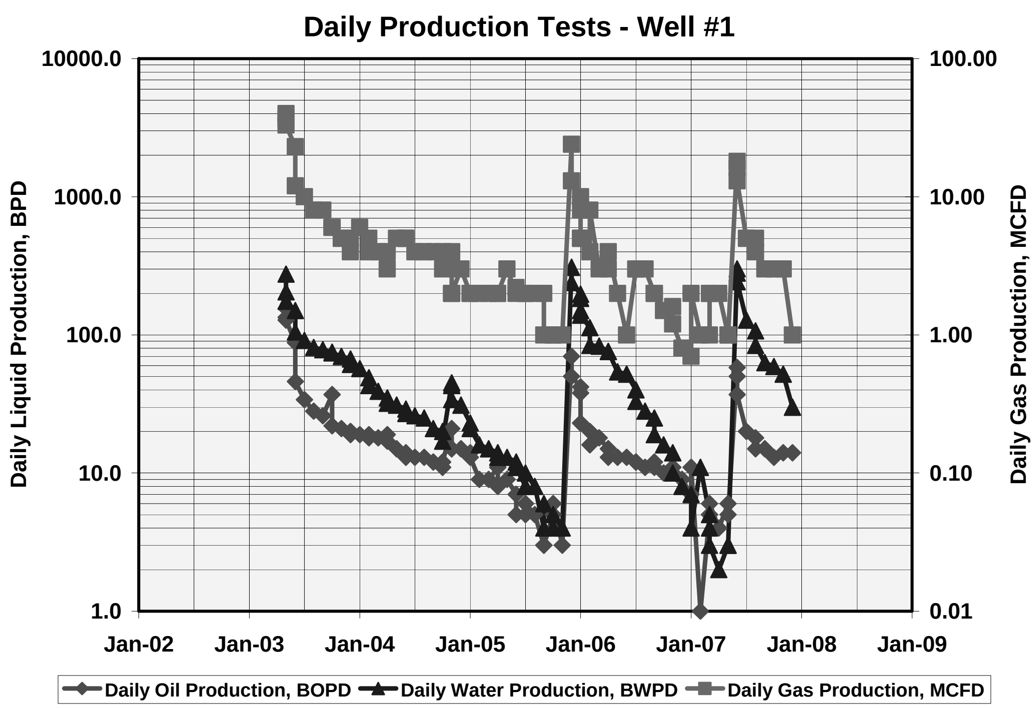

Figure 5 – Daily Production tests on Well No.1

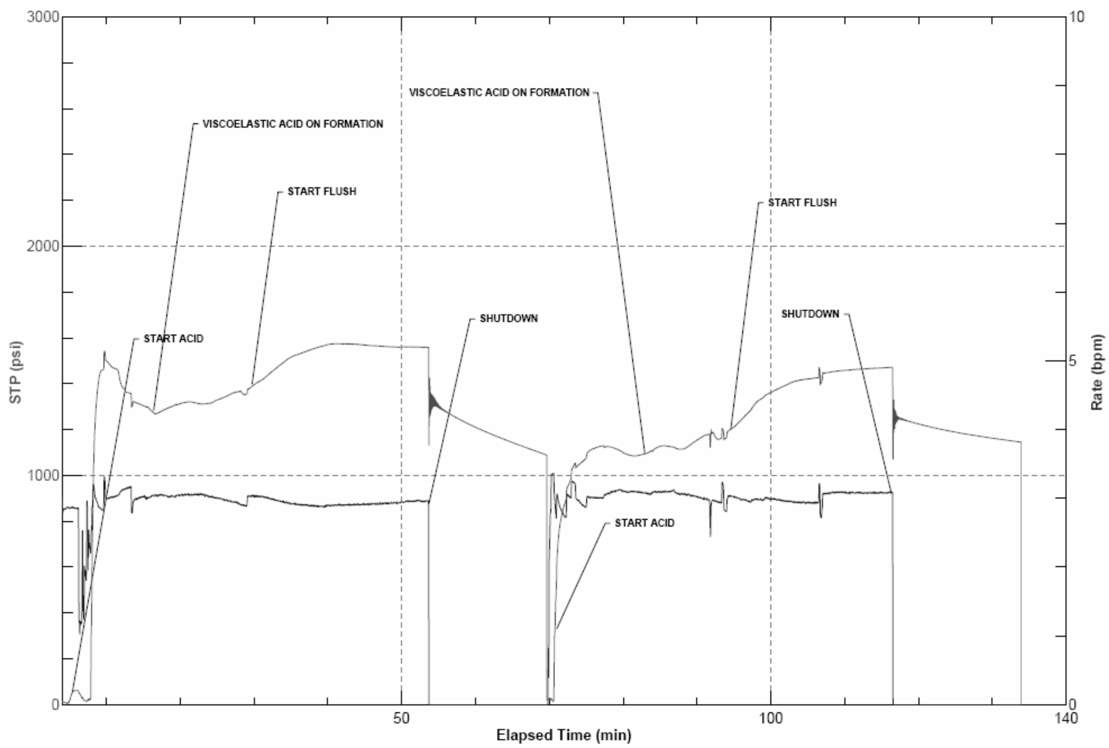

Figure 6 – Rate & Pressure Chart for Treatment of Well No.2

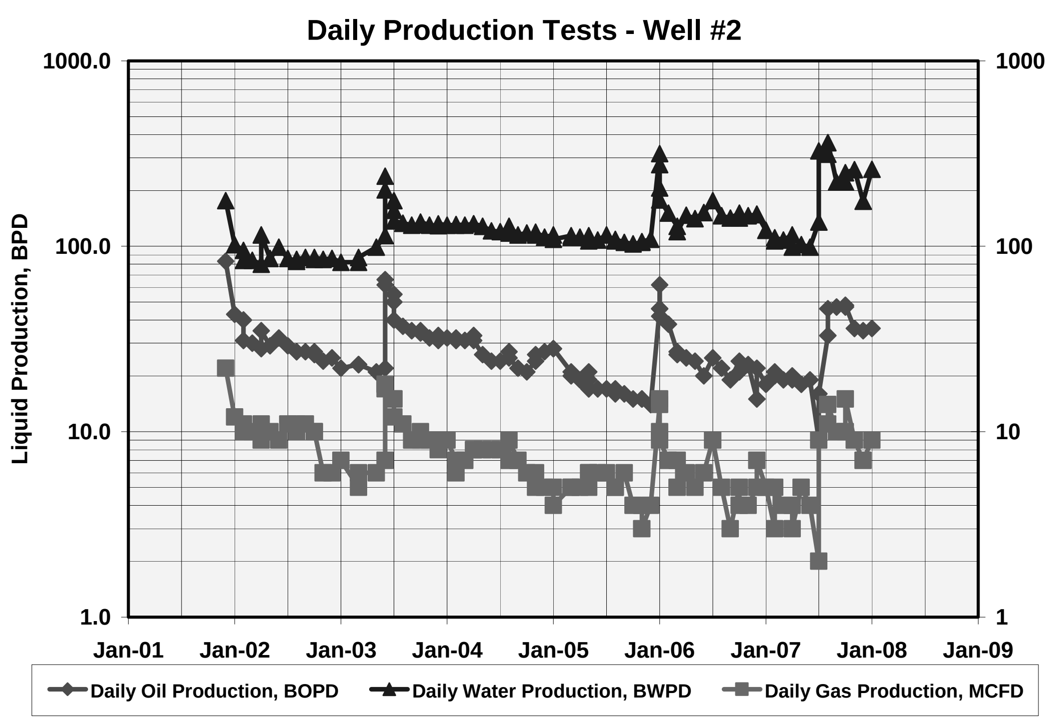

Figure 7 – Daily Production tests on Well No.2

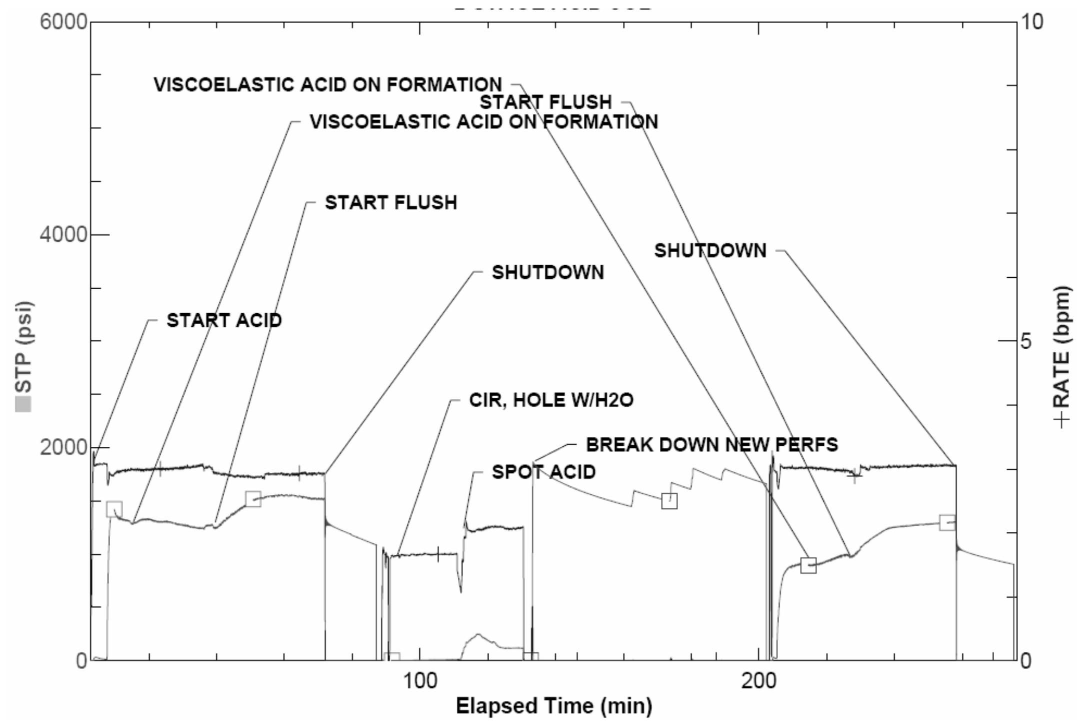

Figure 8 – Rate & Pressure Chart for Treatment of Well No.3

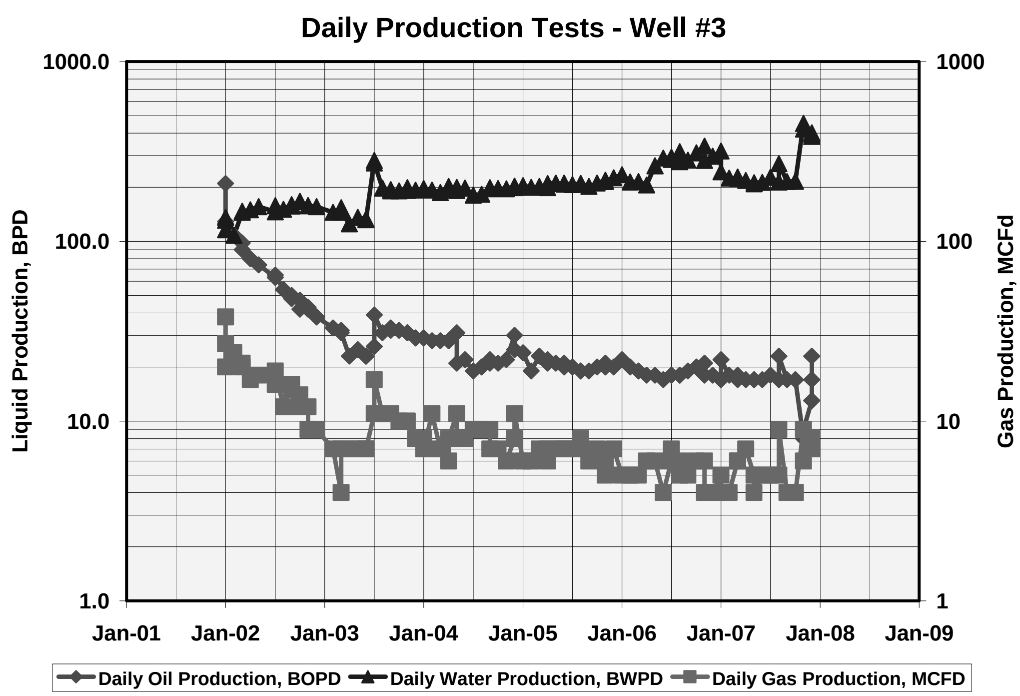

Figure 9 – Daily Production tests on Well No.3