TITLE: CONTROL OF WATER PRODUCTION USING DISPROPORTIONATE PERMEABILITY REDUCTION IN GELLED POLYMER SYSTEMS

FINAL REPORT

Reporting Period Start Date: July 1, 2005

Reporting Period End Date: December 31, 2006

Principal Author: G. Paul Willhite

Tertiary Oil Recovery Project
1530 W. 15th Street
Room 4146B Learned Hall
Lawrence, Kansas 66045-7609
email: willhite@ku.edu
phone: 785-864-2906

Date Report was Issued: (April 2007)

DOE Award Number: DOE Contract No. DE-FC26-04NT42098 (Subaward No. 2937-UK-DOE-2098)

Submitting Organization: University of Kansas Center for Research, Inc. 2385 Irving Hill Road Lawrence, KS 66044

Participating Subcontractor: Vess Oil Company, 8100 E. 22nd North, Building 300, Wichita, KS, 67226

DISCLAIMER:

ABSTRACT:

The objectives of this project were to reduce water production and increase oil production following a gelled polymer treatment by a post placement process in which some of the gel that formed in situ is dehydrated by injection of oil to create flow channels that exhibit preferential permeability to oil and significantly lower permeability to water. The project involved three gel polymer treatments in the Arbuckle formation in Central Kansas on leases where treatments by the conventional process have been done, establishing a general baseline of the post-treatment performance for comparison. The gelant system used was a chromium carboxylate-polymer system currently used to treat Arbuckle wells in Central Kansas.

Three wells in the Bemis Shutts Field, Ellis County, Kansas were given gel polymer/dehydration treatments. Sustained reduction in water production was achieved in two of the three wells treated. Incremental oil was produced in two of the wells. One well did not respond to the gel treatment. In wells producing incremental oil, oil rates eventually declined to pretreatment rates or below pretreatment rates within a few months after treatment. Two wells that received the designed gelant treatment sustained reductions in water production over periods of 12-18 months after treatment. Conversion from a submersible pump to a beam pump in McCord A#1 resulted in a savings of $5,000/month in electrical costs. Colahan A#28 produced 1130 bbl of incremental oil before production of incremental oil ceased. Incremental oil production from McCord A#1 was 887 bbl and declined below the pretreatment value about five months after treatment. The treatment of Hall B#4 was not successful, but is not related to the dehydration process. Results from the post treatment process of oil injection to dehydrate the gel after placement are inconclusive when compared to wells in which the gel was not dehydrated after placement.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

Objectives -

The objectives of this project are to reduce water production and increase oil production following a gelled polymer treatment by a post placement process in which some of the gel that formed in situ is dehydrated by injection of oil to create flow channels that exhibit preferential permeability to oil and significantly lower permeability to water. The project involves three gel polymer treatments in the Arbuckle formation in Central Kansas on leases where treatments by the conventional process have been done, establishing a general baseline of the post-treatment performance for comparison. The gelant system used is a chromium carboxylate-polymer system currently used to treat Arbuckle wells in Central Kansas.

Project Task Overview -

Task 1 Selection of wells for treatment

Tasks 2-6 were done as each well was treated.

Task 2 Prepare well for treatment
Task 3 Perform gel treatment
Task 4 Post treatment dehydration of gel
Task 5 Place well on production

Task 6 Analysis of Performance

Task 6.1 Analysis of data
Task 6.2 Preparation of reports and presentations

Task 7 Participate in SWC and PTTC Workshops

EXECUTIVE SUMMARY:

Three wells in the Bemis Shutts Field, Ellis County, Kansas were given gel polymer/dehydration treatments. Pressure buildup analyses were used to estimate whether each well could be treated with a large volume gel treatment. Colahan A#28 was treated in July 2005 and placed on production. As of December 31,2006, the oil rate was ~10 B/D and the water rate was about 146 B/D with the well pumped off. Incremental oil from the treatment is about 1130 BBL.

A second well (McCord A#1) was treated in December 2005 , the gel dehydrated and was placed on production in January 2006. The water production rate was reduced from 3260 B/D to 250 B/D with the well pumped off. Replacement of a submersible pump with a beam pumping unit resulted in estimated savings in electrical costs of $5,000/month. Incremental oil was produced in this well, but the oil rate declined below the pretreatment rate by the middle of the year, decreasing the amount of incremental oil attributed to the treatment.

The third well treated(Hall B#4) did not respond to the gel treatment for reasons that are not understood. There was neither a reduction in oil rate nor production of incremental oil when the well was placed on production following the dehydration process. The lack of this response is not believed to be due to the dehydration process.

Results from the post treatment process of oil injection to dehydrate the gel after placement are inconclusive when compared to wells in which the gel was not dehydrated after placement.

RESULTS AND DISCUSSION:

Task 1 Selection of wells for treatment: Four wells operated by Vess Oil Company were identified as potential candidates for gel polymer treatments. Buildup tests were conducted on each well using a computerized Echometer to estimate the kh of the well and the flow environment in the vicinity of the well. Figure 1 shows the location of the four wells on leases operated by Vess Oil Company. Table 1 summarizes data for these wells.

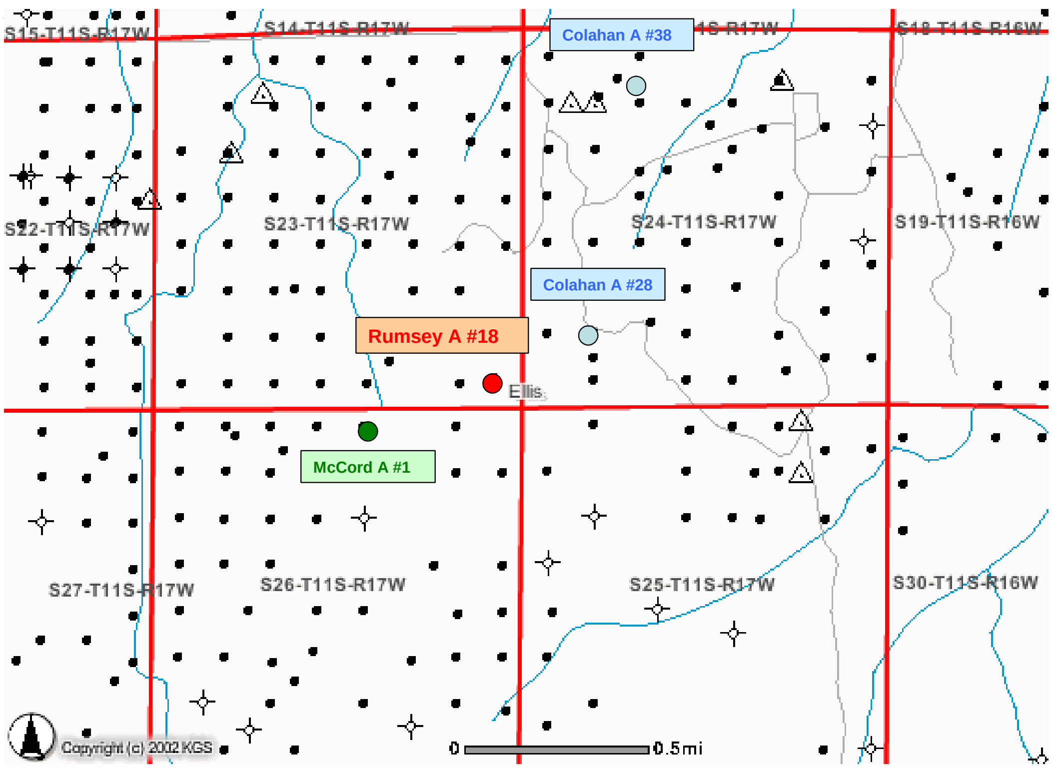


Figure 1: Map of Vess Oil Leases in the Bemis Shutts Field Showing Candidate Wells

Colahan A#38 was treated and was removed from the program because of high pressures during injection and limited volume of gelant that was injected. Rumsey A#18 had similar characteristics to Colahan A#38, specifically a short perforated interval. McCord A#1 was selected for the second well to be treated. Hall B#4 was selected as the third well. The location of Hall B#4 is shown on Figure 2. Table 1 summarizes data for these wells.

Table 1: Summary of Well Data-Pre Treatment Analysis

	Colahan #28	McCord A#1	Hall B#4
Depth to Top of Arbuckle, feet	3558	3476	3413
Completion	Perforated-4 shots/ft	Open Hole	Open Hole
Interval open for production	3560-3567	3477-3487	3413-3423
Net Thickness open, ft	7	10	10
Oil Rate, B/D	6	9	12
Water Rate, B/D	500	3210	540
Pump intake depth, ft	3576	3310	3349
Type of pump	Rod	Submersible	Rod
Fluid level above pump, ft	1703	1080	1189

Vess Oil Corporation – DPR Wells, Bemis-Shutts Field

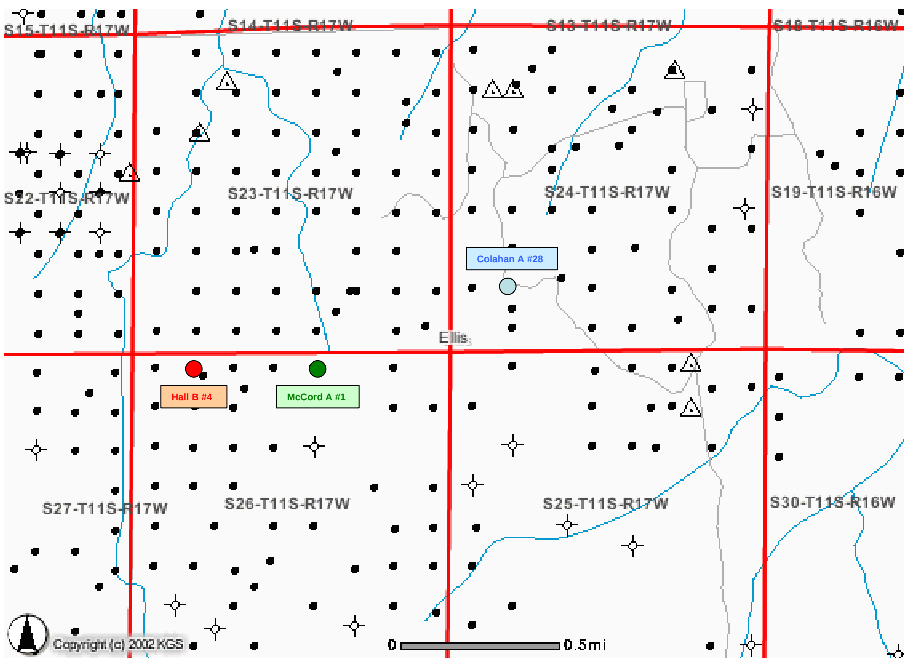


Figure 2: Map of Vess Oil Leases in the Bemis Shutts Field Showing Treated Wells

Well No. 1: Colahan A#28

Figure 3 illustrates the buildup test from Colahan A#28, the first well selected for gel treatment. Buildup tests in Arbuckle reservoirs are characterized by rapid response following shut-in. A stable reservoir pressure of ~790 psi(804.7 psia) was reached within 45 minutes after the well was shut-in. Interpretation of the buildup data is affected by wellbore storage. A radial flow model was used to match the buildup data using Pan Sys, a commercial software package. Prior to shut-in, the well was producing 500 BWPD and 6 BOPD with the fluid level at 1703 feet above the pump. Estimated

$k_w h$ for the well was ~1600 md-ft. This is sufficient kh for the polymer treatment. Net oil thickness is not known because the well was completed in the top 7 ft of the reservoir interval as is the common completion practice.

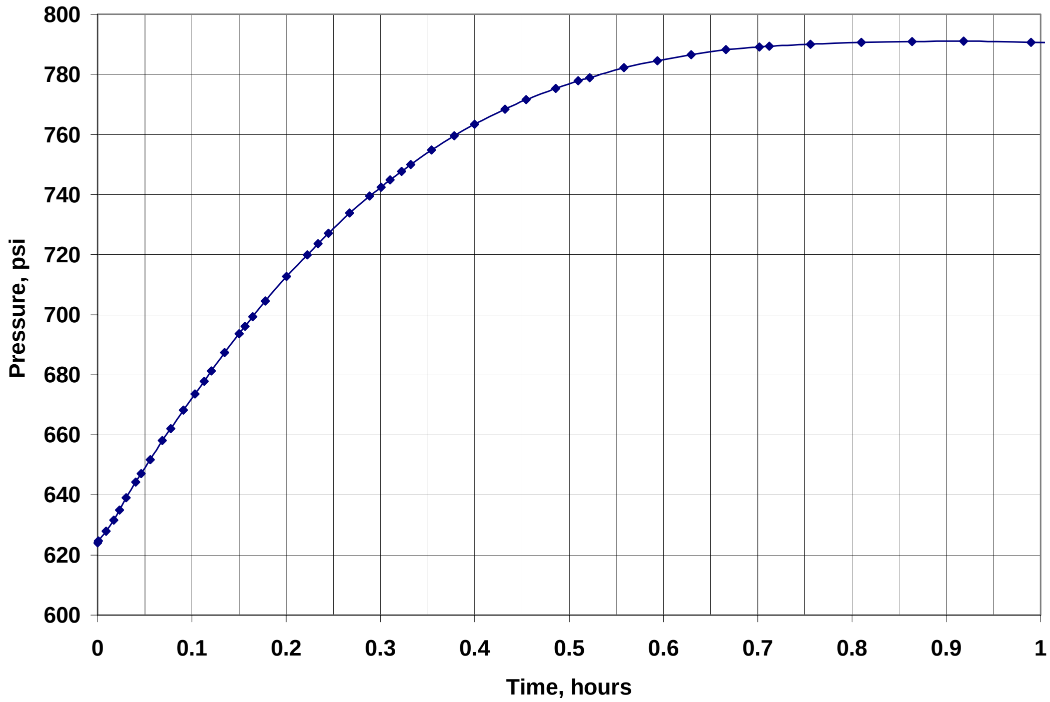


Figure 3: Pressure buildup in Colahan A#28

Task 2 Prepare well for treatment: Colahan A#28 was prepared for treatment by running a 4 ½" liner to 3484 ft. A tubing string was run on a packer set at a depth of 3428 ft. The well was acidized with 2000 gallons of 15% HCL acid and swabbed.

Task 3 Perform gel treatment: The gel treatment to control water production began on July 22 and was completed on July 25. Treatment data are summarized in Table 2. The treatment was designed by the vendor, following normal treating practice. The gel system was prepared by mixing a partially hydrolyzed polymer solution (Water Cut 204) with chromium acetate solution (Water Cut 684) in line using a trailer mounted skid. The treatment plan consisted of increasing the polymer concentration from 3000-9000 ppm in increments based on the response of the well to fluid injection. Most of the polymer was injected at a rate of 1 BPM.

A total of 3785 barrels of gelant was injected into the well at rates of 1 BPM until the later stage of the treatment where the polymer concentration was increased to 9000 ppm. Bottomhole pressure was monitored with a downhole pressure gauge before, during and after gelant injection. Injection and pressure data are shown in Figure 3. There was a relatively small increase in BHP until the polymer concentration was increased to 6000 ppm. At the end of the treatment, the tubing and casing were flushed with ~30 barrels of crude oil at a high injection rate.

Table 2: Polymer Gel Treatment-Colahan A#28

Stage	Date Begin	Time Begin	Date End	Time End	WC204® Polymer (ppm)	Est. WC204® Polymer Lbs.	Est. WC684® X-Linker Lbs.	Gel Bbls.	Begin Surf. Pres. (psi)	End Surf. Pres. (psi)	Begin BH Pres. (psi)	End BH Pres. (psi)	Pump Rate Begin (BPM)	Pump Rate End (BPM)	Comments
1	7/22/05	7:15 a	7/23/05	8:13 a	3000	1600	347	1522	Vac	Vac	840	953	1.0	1.0	Stage complete
2	7/23/05	8:13 a	7/23/05	8:13 p	4500	1150	251	735	Vac	Vac	953	1035	1.0	1.0	Stage complete
3	7/23/05	8:13 p	7/24/05	8:19 a	6000	1550	336	735	Vac	Vac	1035	1218	1.0	1.0	Stage complete
4	7/24/05	8:19 a	7/25/05	2:30 a	9000	2500	542	793	Vac	205	1218	1658	1.0	0.75	Stage complete
Totals						6800	1476	3785							

Bottomhole pressure and temperature data were obtained during the treatment and are shown in Figure 5. The initial bottomhole pressure was 853 psia, about 50 psi higher than determined from the pressure buildup tests that were done prior to the treatment. The bottomhole pressure gauge was set at a depth of 3437 feet, about 127 feet above mid-perforation depth. Actual pressures at the sandface were approximately 53 psi higher than shown in Figure 5.

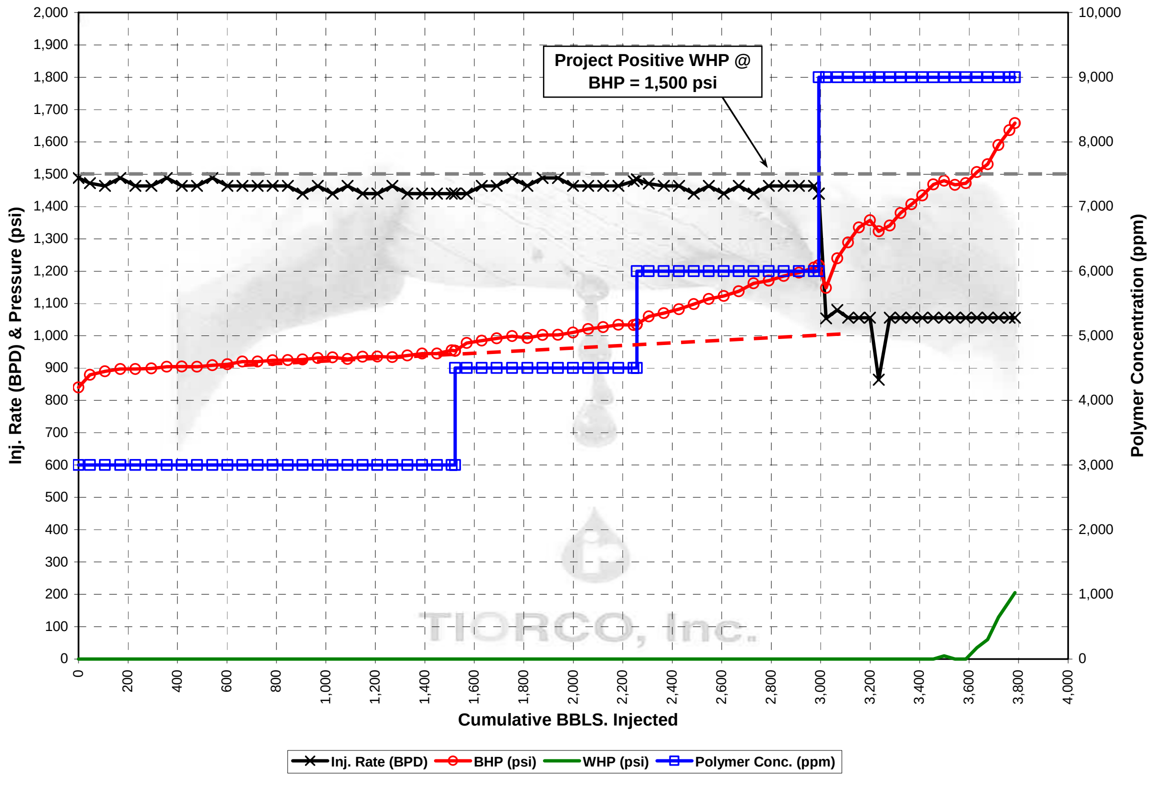


Figure 4: Data from treatment of Colahan A#28

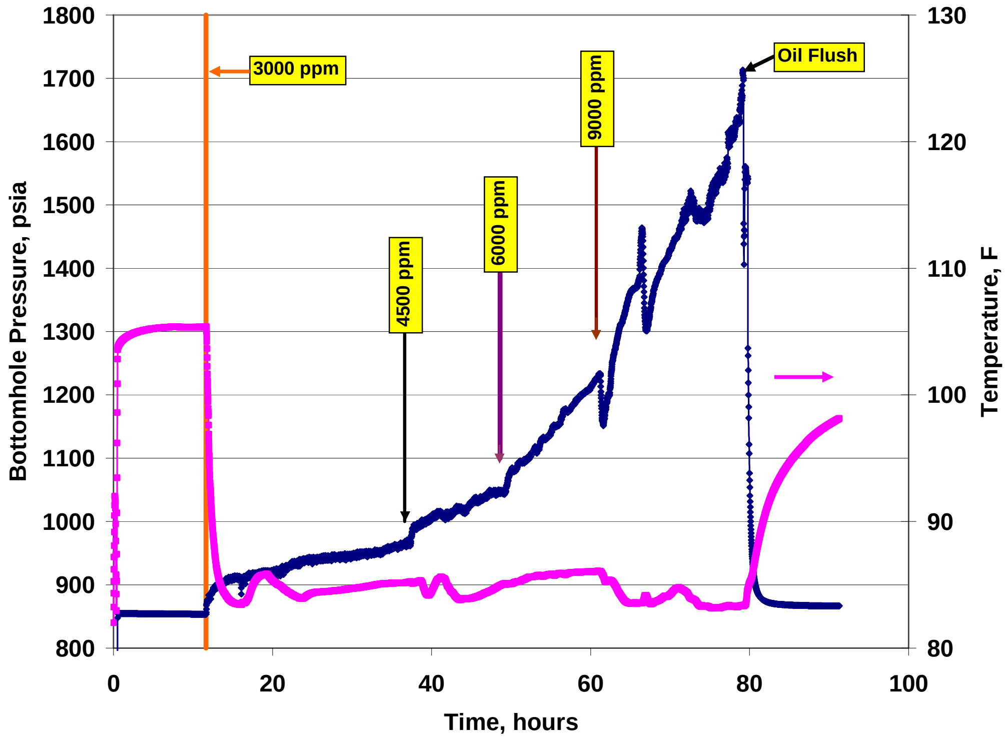


Figure 5: Bottomhole pressure and temperature data during gel treatment of Colahan A#28

Task 4 Post treatment dehydration of gel: The well was shut in for ~10 days before beginning the DPR treatment. Oil was injected from a 100-barrel supply tank at a rate of approximately 10 B/D for seven days. A bottomhole pressure gauge was installed in the well prior to the beginning of oil injection to measure pressure increase so that the pressure gradient during dehydration of the gel could be monitored and controlled as necessary.

Oil was injected into the well with less pressure drop than anticipated. Pressure drop and injection rates are shown in Figure 6 during the dehydration process. Maximum pressure increase was about 40 psi.. The bottomhole pressure fell off rapidly to the initial reservoir pressure within a few hours after termination of oil injection.

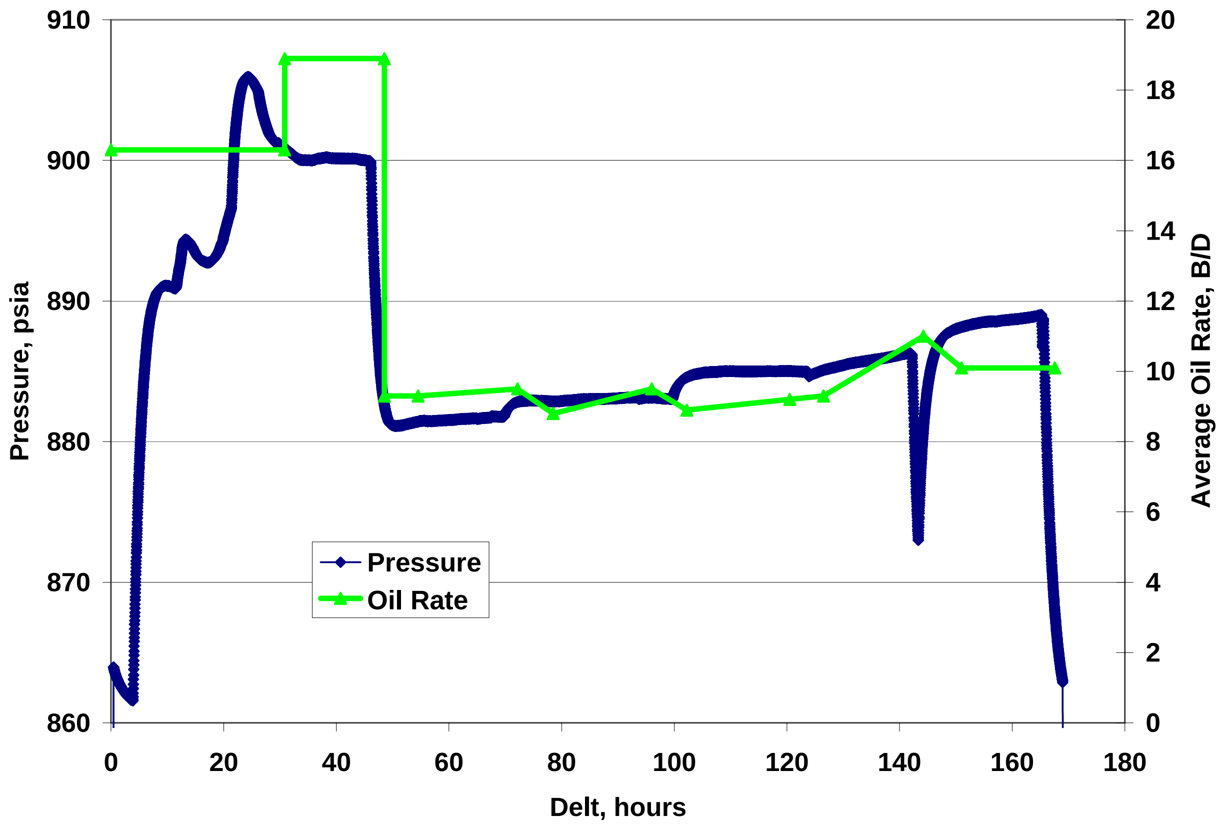


Figure 6: Pressure and Oil Injection Rate During Dehydration Process-Colahan A#28

Task 5 Place well on production: Colahan A#28 was placed on production on August 12, 2005. Oil and water production rates following the treatment are shown in Figure 7. The initial increase in oil rate is in part due to the recovery of the oil used to displace the tubing following treatment and the volume of oil injected during the dehydration process. Although the peak oil rate is less than desired, the incremental oil was produced throughout the period of this report. Water production rate was reduced from 500 B/D with a fluid level of 1703 ft above the pump to about 146 B/D with the well pumped off.

Task 6 Analysis of Performance: Oil and water rates following the treatment are shown if Figure 7. The oil rate has declined to pretreatment levels. Incremental oil from this treatment is estimated to be 1130 BBL as of the end of December 2006. Post treatment water rate stabilized at about 155 B/D for a period of over 18 months after treatment compared to the pretreatment rate of 518 B/D. The well is pumped off.

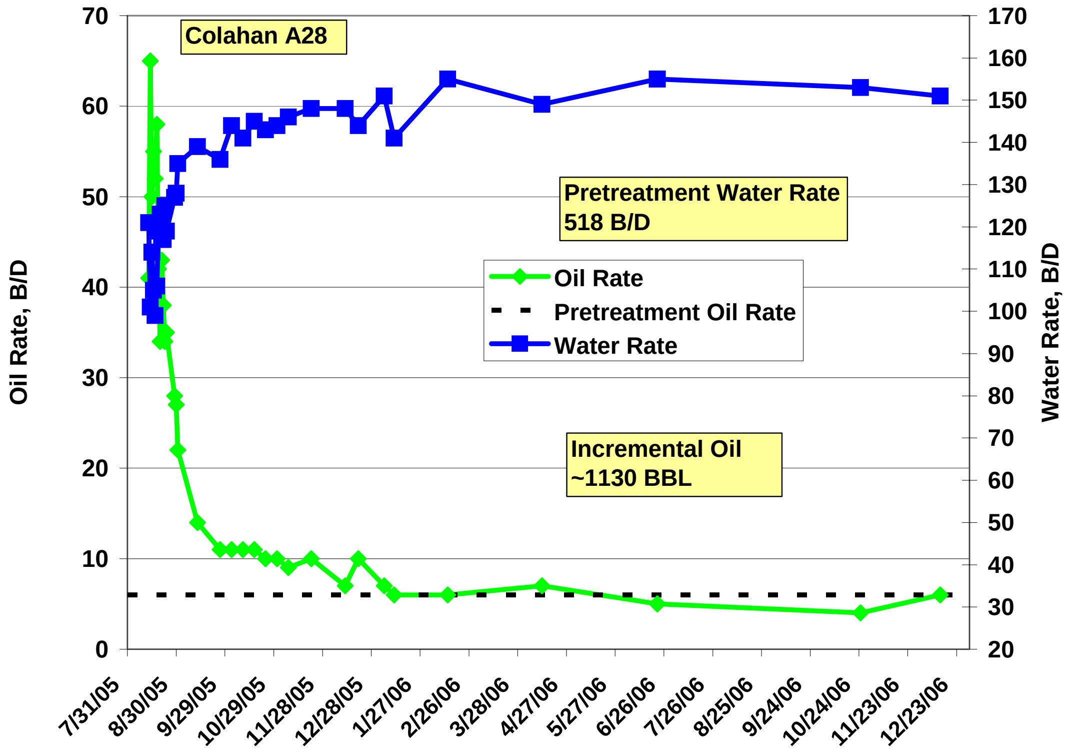


Figure 7: Oil and water production rates following gelled polymer treatment in Colahan A#28

In addition to the production data, water samples were taken to determine polymer and chromium concentrations during the first month the well was placed on production. It is well known that excessive polymer in the produced fluid can strip corrosion inhibitors from the rods leading to corrosion and rod failure. Polymer concentrations were determined using Total Oxygen Carbon Analysis and are expressed as carbon concentration. The polymer concentration is approximately 2 times the carbon concentration. Chromium (III) concentration was determined by oxidizing Cr (III) to Cr (VI) and measuring the absorbance in the UV ranges. Figure 8 shows the carbon and chromium concentrations following the treatment and dehydration in Colahan A#28. Chromium concentration was less than 1 ppm. Carbon concentration dropped from about 250 ppm to 140 ppm during the first month of production. Polymer concentration is approximately twice the carbon concentration, so that polymer concentrations decreased from about 500 ppm to 280 ppm during this time period.

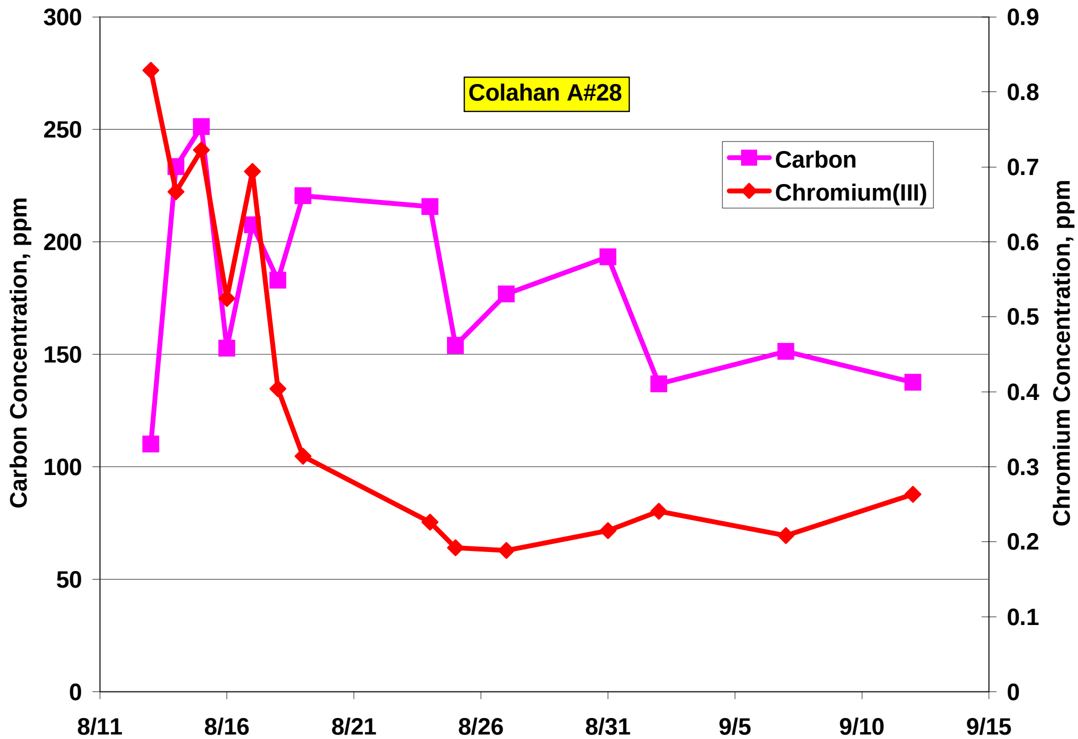


Figure 8: Carbon and chromium (III) concentrations in the produced water from Colahan A#28

Well No. 2- Colahan A#38:

The second well selected for treatment was Colahan A#38. The pressure buildup for this well is shown in Figure 9. Wellbore storage effects dominate the buildup data and a substantial skin was identified. However, because the value of $k_w h$ for the well was estimated to be several thousand md-ft, plans were made to prepare the well for treatment.

Task 2 Prepare well for treatment: Colahan A#38 was prepared for treatment by pulling the tubing and pump, running a tubing string on a packer set at a depth of 3558 ft. The well was acidized with 2000 gallons of 15% HCL acid and swabbed.

Task 3 Perform gel treatment: A new vendor was selected for this treatment by the operator. The gel system was prepared using partially hydrolyzed polymer delivered as an emulsion and chromium propionate crosslinking agent. Design of the treatment was done by the vendor based on prior experience in the field. The gel treatment was completed on September 12-13, 2005. During the treatment, the bottomhole pressure increased rapidly, limiting the treatment to about 1550 barrels of gelant injected. Vess Oil offered to remove this well from the program and substitute another well for the second well in the SWC program. The offer was accepted and no charges will be incurred in this project for treatment of Colahan A#38.

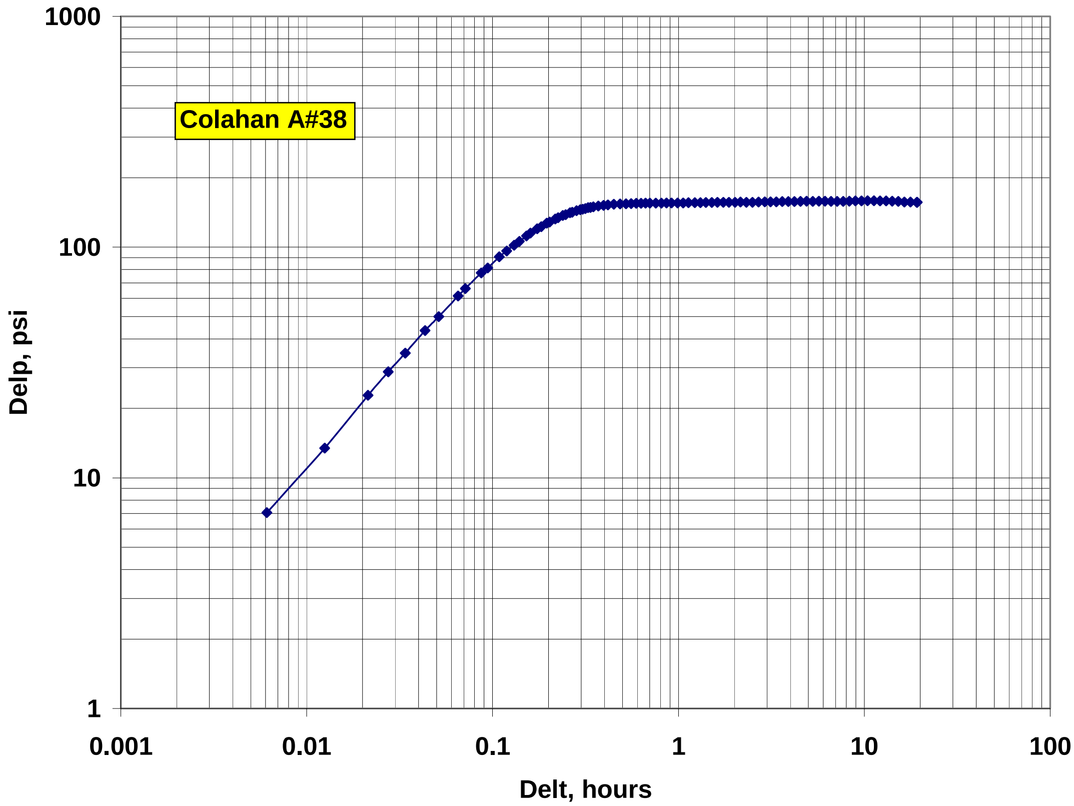


Figure 9: Pressure buildup in Colahan A#38

Task 6: Analysis of Performance: Although the test was completed on Colahan A#38, detailed results are not reported as part of this contract. However, observations made during the treatment have changed the criteria for selection of candidate wells. Pressure losses of 300-500 psi were observed during gel injection when the well was shut-in for time intervals of 1-2 minutes. These losses appear to be a near wellbore phenomena rather than a reservoir condition.

Colahan A#38 was completed in a 3 foot interval with four-0.3-0.35" perforations per foot for a total of 12 perforations. The well was acidized before treatment, but there is no way of knowing if all perforations were open during polymer injection. It appears that there was excessive pressure drop across the perforations during injection of this polymer system, leading to rapid increase in pressure, which limited the volume of gelant that was injected.

A review of a large number of treatments in our database was made to determine if wells with limited perforated intervals had been treated successfully. Nearly all wells were either completed open hole or had large perforated intervals open for production. Rumsey A#18 was eliminated from potential candidates because this well has two feet of perforated interval open for production. McCord A#1 was selected for the second treatment.

Well No. 2-Revised: McCord A#1

Pressure buildup data were collected in McCord A#1 using our computerized Echometer to verify that the well had adequate kh to receive a full gel treatment. Figure 10 shows the increase in pressure following shut-in of the well. The fluid level rose rapidly and the majority of the pressure increase occurred within 6-10 minutes after the well was shut-in. Wellbore storage effects dominate the data, making interpretation of the buildup data difficult. However, the kh was judged to be sufficient for the gel test.

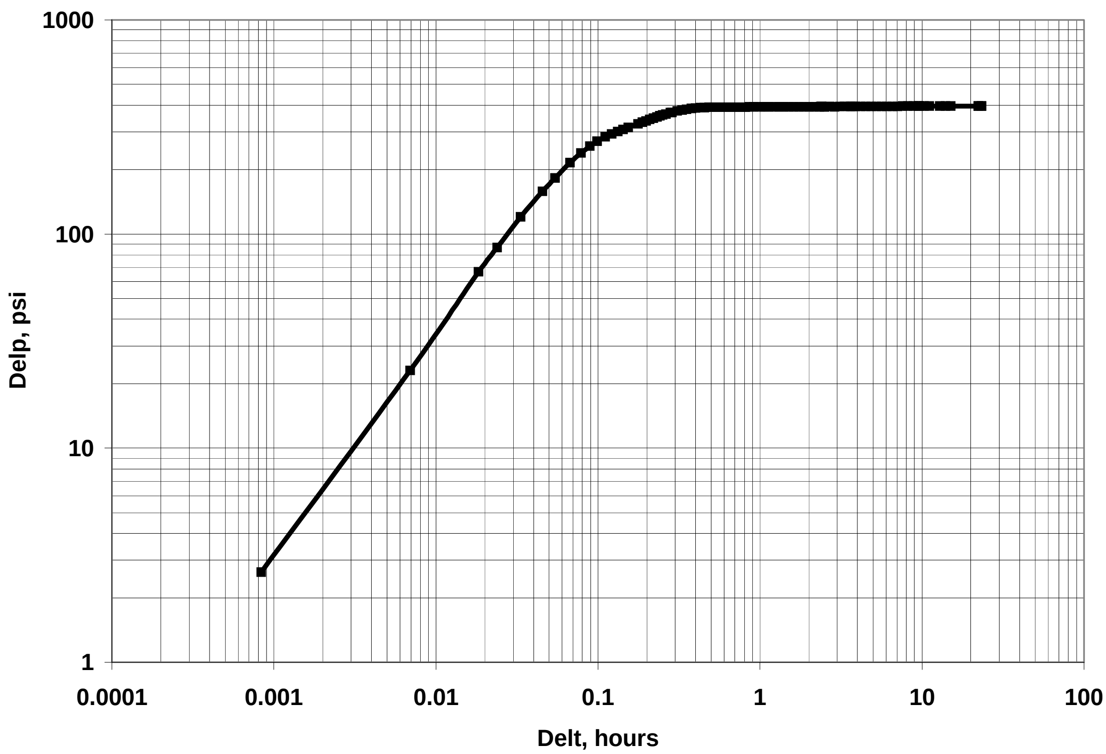


Figure 10: Pressure buildup in McCord A#1 prior to gel treatment

Task 2 Prepare well for treatment: On November 21, 2005, the electrical submergible pump (ESP) was pulled from the well and laid down. A sand pump was then run to clean the wellbore to 3497'. A total of 2 gallons ferric sulfide was recovered. On November 22, 2005, a packer and tubing were run in the well. The packer was set and pressure tested at 3361'. The well was acidized with 2000 gallons of 15% HCl containing surfactants and iron stabilizing chemicals. The well treated at 6.3 bpm with a 700 psig surface treating pressure. The maximum pressure reached during the acid treatment was 800 psig. The acid was flushed with 80 barrels saltwater. The well immediately went on a vacuum upon completion.

Task 3 Perform gel treatment: The treatment was conducted by TIORCO, Inc on December 1-5. Details of the treatment are given in Table 3. The treatment was done in four stages beginning with 3000 ppm and finishing with 9000 ppm. Treatment volume was 5046 barrels of gelant. A larger treatment was used because the pressure buildup during injection was slower than anticipated and the operator wanted to finish the job with a high concentration slug. Figure 11 shows the bottomhole pressure, polymer concentration and injection rate during the treatment. Figure 12 shows the bottomhole pressure and temperature during the treatment. At the end of the treatment, the gelant was displaced with 24 barrels of lease crude and the well was shut-in to permit insitu gelation. The shut-in period extended through the remainder of December 2005.

Table 3: Summary of Gel Treatment-McCord A#1

Stage	Date Begin	Time Begin	Date End	Time End	WC204® Polymer (ppm)	Est. WC204® Polymer Lbs.	Est. WC684® X-Linker Lbs.	Gel Bbls.	Begin Surf. Pres. (psi)	End Surf. Pres. (psi)	Begin BH Pres. (psi)	End BH Pres. (psi)	Pump Rate Begin (BPM)	Pump Rate End (BPM)	Comments
1	12/1/05	9:17 a	12/2/05	5:58 p	3000	1542	335	1470	Vac	Vac	838	897	0.75	0.75	Stage complete
2	12/2/05	5:58 p	12/4/05	3:13 a	4500	2368	515	1505	Vac	Vac	897	983	0.75	0.75	Stage complete
3	12/4/05	3:13 a	12/5/05	2:10 p	6000	3302	718	1574	Vac	Vac	983	1236	0.75	0.75	Stage complete
4	12/5/05	2:10 p	12/6/05	2:30 a	9000	1564	340	497	Vac	90	1236	1476	0.75	0.75	Stage complete
Totals						8776	1908	5046							

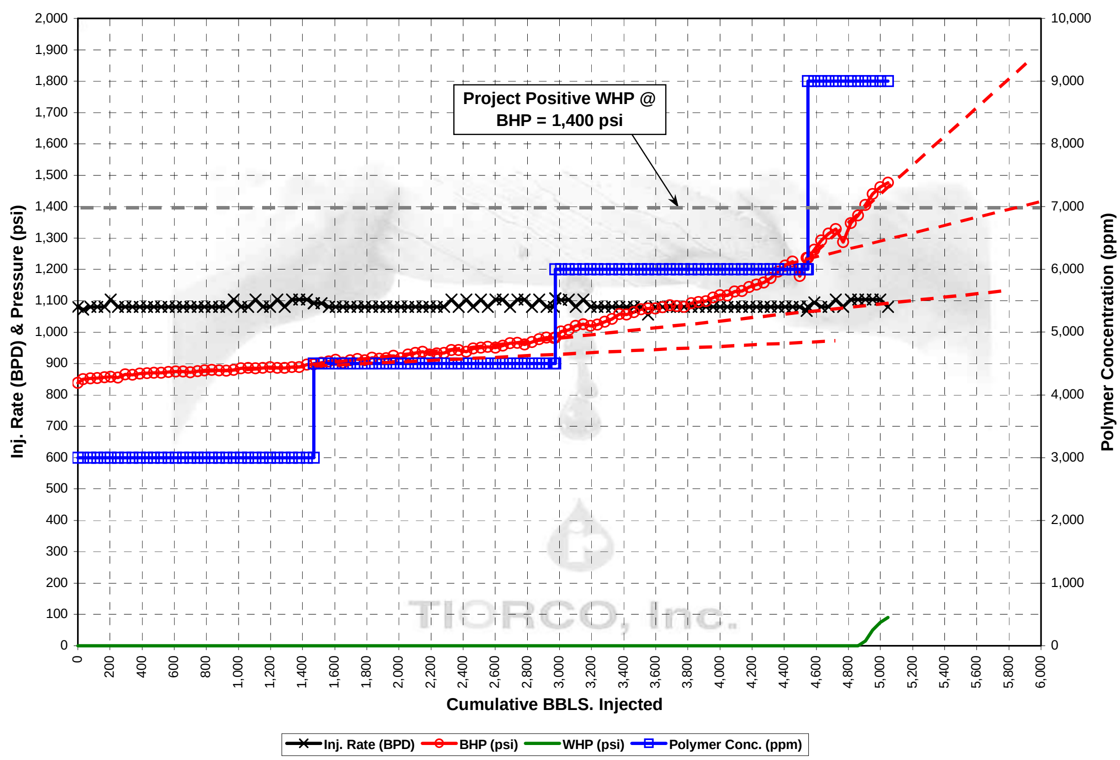


Figure 11: Injection rate, bottomhole pressure and polymer concentration during McCord A#1 gel treatment

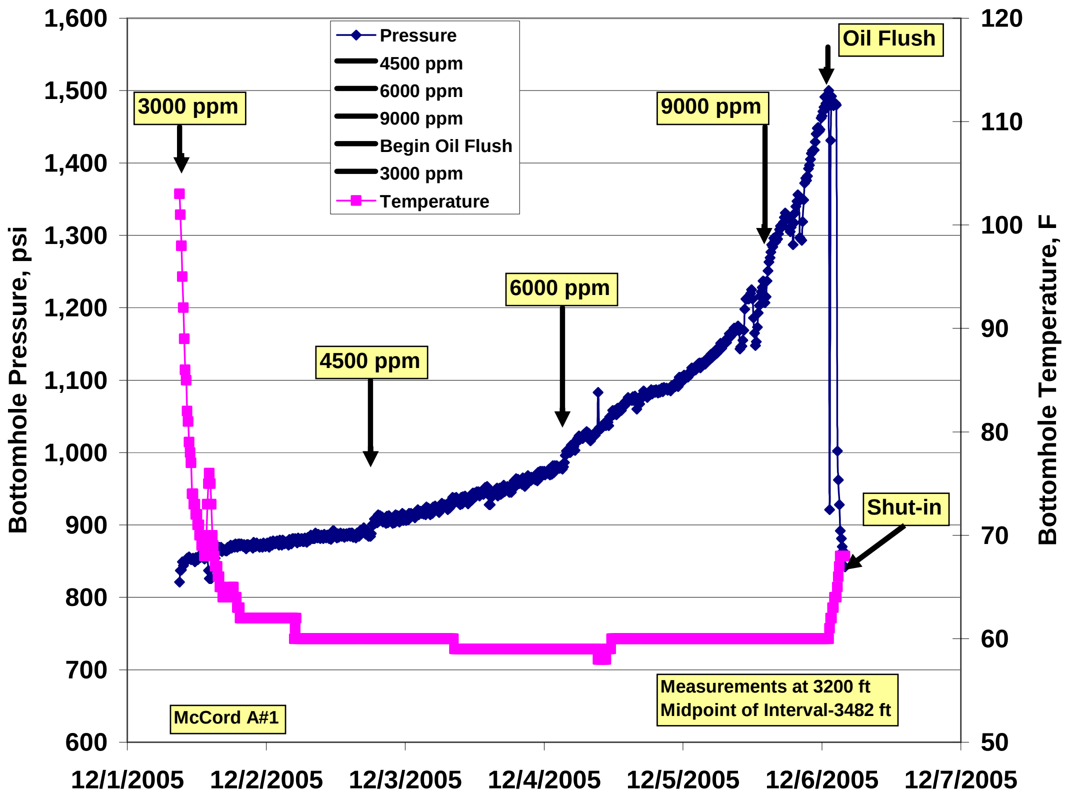


Figure 12: Bottomhole pressure and temperature data during gel treatment of McCord A#1

Task 4 Post treatment dehydration of gel: The dehydration of the gel was conducted on the McCord A #1 from January 2, 2006 to January 13, 2006. The well was shut-in for 27 days after the gel treatment to permit in-situ gelation and to accommodate schedules surrounding the holiday season. The DPR treatment consisted of pumping 106 bbls of lease crude oil into the gel-treated interval of the reservoir at an average injection rate of 9.6 bopd. The treatment took eleven days to complete.

The treatment was conducted using a low-volume, high-pressure pump provided by the vendor. The crude oil was pumped down tubing under a packer. Throughout the DPR treatment, the well's bottom-hole pressure was monitored at surface using a real-time, bottom-hole pressure (BHP) recorder located at a depth of 3200 ft. The static mid-perf BHP at the well prior to the treatment, as measured by the BHP recorder, was 962 psig. As crude oil was slowly pumped into the gel-treated interval, the well's BHP steadily rose such that by the end of the treatment (day 11) the BHP had risen to a high of 1019 psig, an increase of 57 psig. At no point during the treatment was surface pressure encountered. Figure 13 shows the bottomhole pressure during the DPR treatment and following shut-in of the well.

The DPR treatment was terminated after 106 bbls lease crude was pumped. A 14-hour fall-off test was then conducted on the well. By the end of the fall-off test, the BHP had fallen to 972 psig. After the fall-off test, the well was shut-in five days pending the availability of a production rig. From January 18 through 24, 2006, the BHP recorder was removed from the well, the packer and tubing was pulled, and rod lift equipment was installed (tubing, pump, rods, and pumping unit). The well was returned to production January 25, 2006.

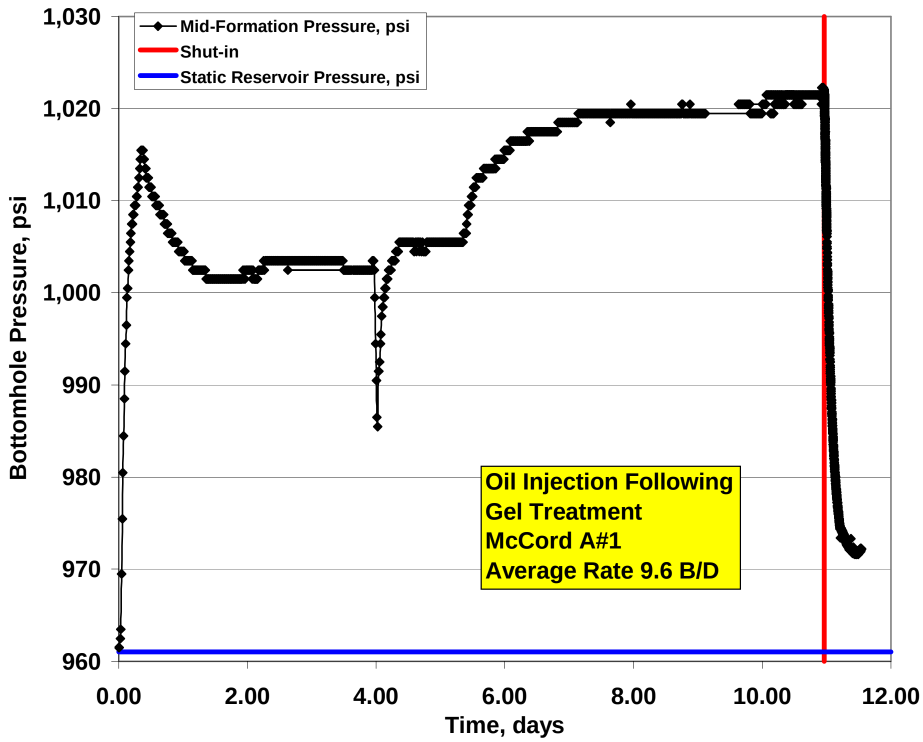


Figure 13: Bottomhole Pressure During Dehydration Process-McCord A#1

Task 5 Place well on production: The well was placed on production with a beam unit replacing the submersible. The well was shut-in for a longer period than usual because a pumping unit had to be moved in.

Task 6 Analysis of Performance

Task 6.1 Analysis of data: Production rates for oil and water are shown in Figure 14 for the period of January 1-December 31, 2006. Water production rates during this time period averaged 155 B/D, a reduction of 3056 B/D. Oil rates after treatment increased to 75 B/D before beginning to decline. The oil rate was on an exponential decline as shown in Figure 14, stabilizing at a rate of 5 B/D. The pretreatment rate was 9 B/D. The amount of incremental oil was estimated to be about 887 barrels at the end of December 2006. Since the well was pumped off, the gel treatment also reduced the stabilized oil rate by about 4 B/D at the end of December. The reduction in water rate appears to be sustained at about 240 B/D. Savings in electricity costs from switching from the submersible to beam pumping unit are about $5,000/month.

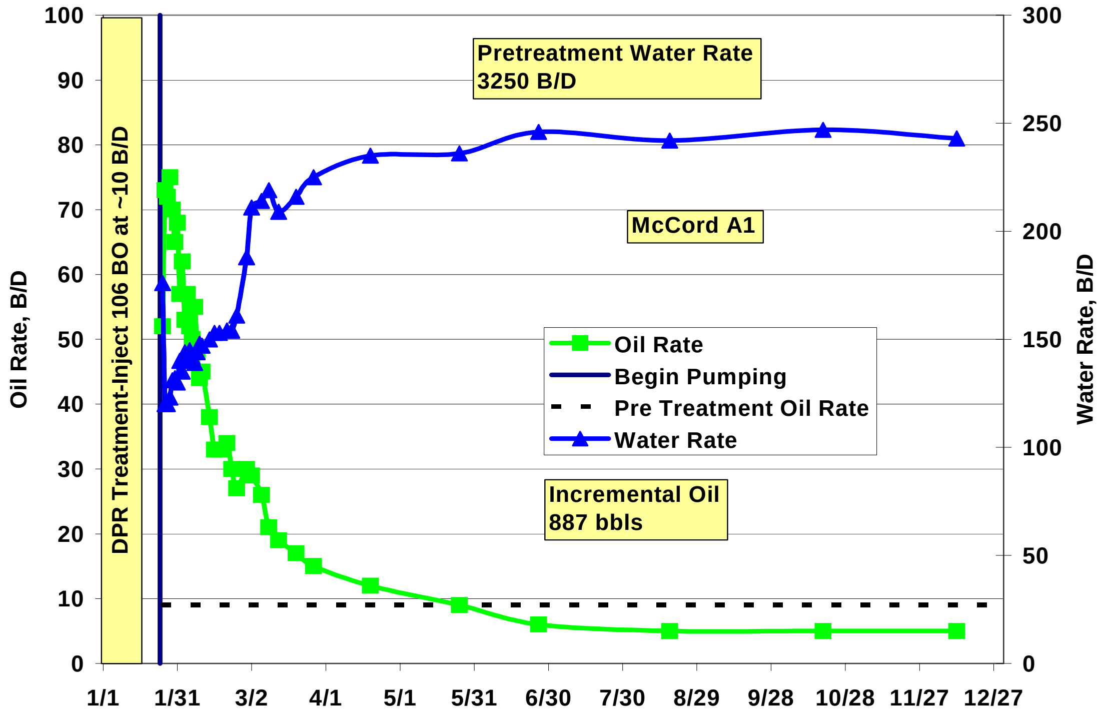


Figure 14: Oil and water production rates from McCord A#1 following gel treatment and dehydration

Produced water samples were analyzed for chromium and polymer following the treatment. Results of the analysis for McCord A#1 are shown in Figure 15. Chromium concentrations were less than 1 ppm throughout much of the post treatment period. Polymer concentration, reported as ppm carbon, gradually declined with time, remaining at about 33 ppm at the end of the sampling period. Polymer concentrations are of interest because polymer strips the corrosion inhibitor from the rods increasing the rate of corrosion.

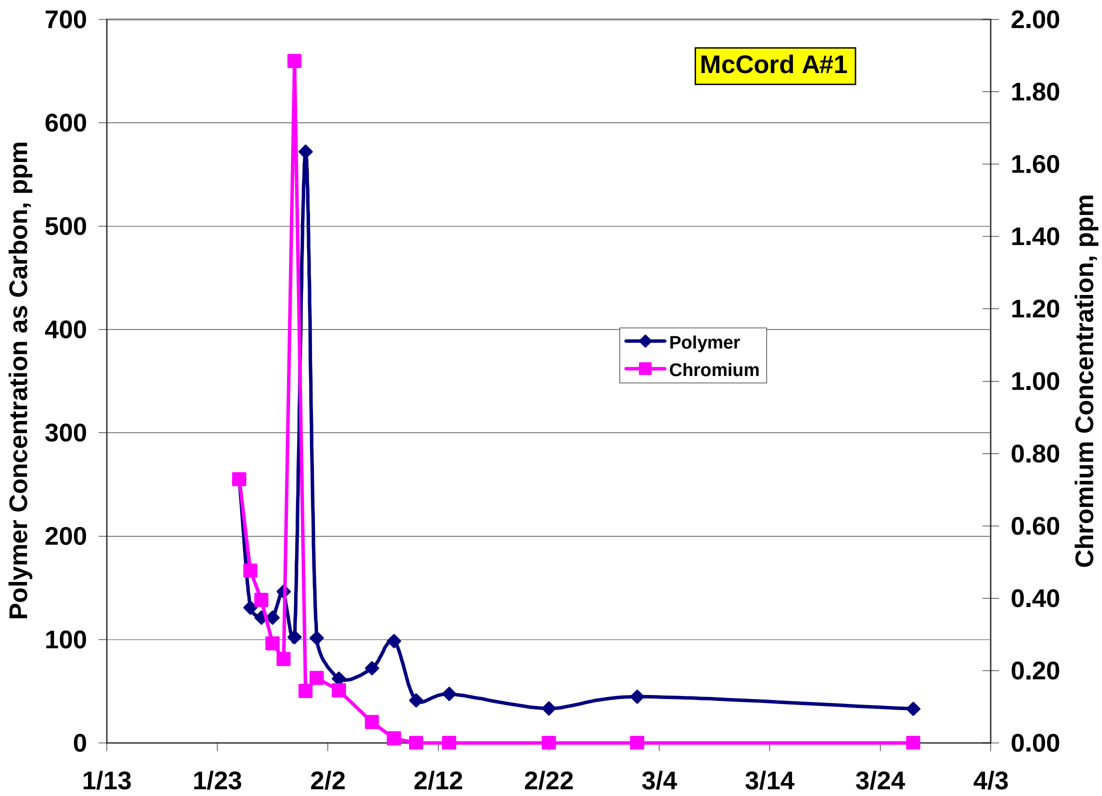


Figure 15: Polymer and chromium concentration in produced water samples following the gel treatment in McCord A#1.

Well No. 3. Hall B#4.

The third well selected for treatment was Hall B#4. This well was previously treated with a 2300 bbl of gelant in October 2002 and produced about 7817 bbl of incremental oil. The well was still producing incremental oil when selected for retreatment but the water rate had increased to 540 B/D.

Pressure buildup data were collected in Hall B#4 using our computerized Echometer to verify that the well had adequate kh to receive a full gel treatment. Figure 16 shows the increase in pressure following shut-in of the well. The fluid level rose rapidly and the majority of the pressure increase occurred within 60 minutes after the well was shut-in. Wellbore storage and skin effects dominate the data, making interpretation of the buildup data difficult. However, the kh was judged to be sufficient for the gel test.

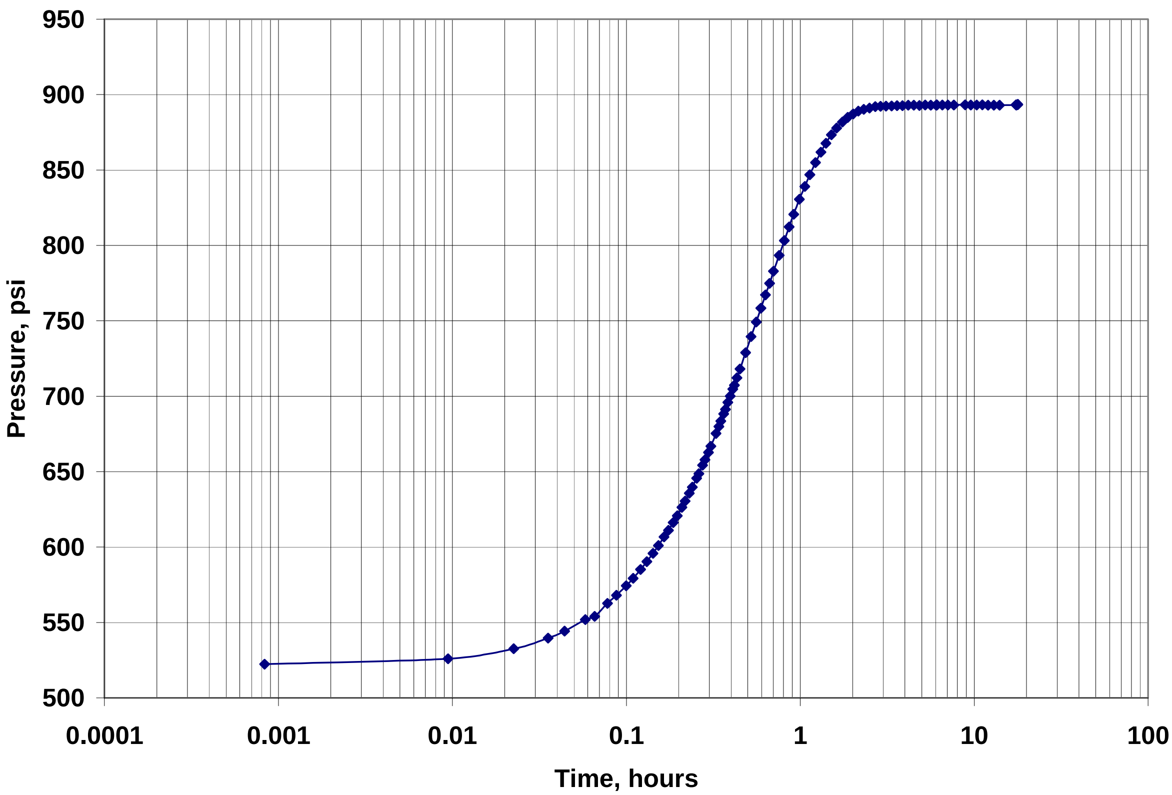


Figure 16: Pressure buildup in Hall B#4 prior to gel treatment

Task 2 Prepare well for treatment: On May 10, 2006 the well was shut in and a work over began. Twenty five rods removed from the well were severely corroded. A sand pump was run three times to clean the wellbore, recovering slightly over 3 gallons of ferric sulfide. On May 11, 2006 a packer and tubing were run in the well. The packer was set and pressure tested at 3308'. The well was acidized with 2000 gallons of 15% HCl containing surfactants and iron stabilizing chemicals. The well treated at 1.3 BPM with a 400 psig surface treating pressure for the first 2.75 bbls, increasing to 7.9 BPM at 1500 psi. The acid was flushed with 102 barrels saltwater. The well immediately went on a vacuum. The well was swabbed for two hours, recovering 73 barrels of water. Swabbing was completed on May 12, 2006 after swabbing a total of 184 barrels of water. Fluid level was 1450 ft from the surface at the end of the swabbing runs.

Task 3 Perform gel treatment: The treatment was conducted by Polymer Systems Inc from May 16-19. Details of the treatment are given in Table 4. The treatment was done in four stages beginning with 4500 ppm and finishing with 8000 ppm. Treatment volume was 4000 barrels of gelant. Most of the treatment was taken on vacuum. Figure 17 shows the bottomhole pressure, polymer concentration and injection rate during the treatment. Figure 18 shows the bottomhole pressure and polymer concentration during the treatment. Temperature was not measured because of an instrument malfunction. At the end of the treatment, the gelant was displaced with 24 barrels of lease crude and the well was shut-in to permit insitu gelation.

Table 4: Summary of Gel Treatment-Hall B#4

Stage	Date Begin	Time Begin	Date End	Time End	WB247® Polymer ppm	WB247® Polymer Lbs.	WB248® X-Linker Lbs.	Gel Bbls.	PSIG Begin	PSIG End	Pump Rate Begin (BPM)	Pump Rate End (BPM)	Comments
1	5/16/06	8:47a	5/16/06	9:05a	0		0		-22		1.0	1.0	Start 25 bbl treated H2O flush
2	5/16/06	9:05a	5/17/06	3:00p	4500	2079	452	1320	-25	-20	.75	.75	40 Bbl. Start Waterblock 247 treatment
3	5/17/06	3:00p	5/18/06	8:11p	5500	2541	552	1320	-20	-19	.75	.75	
4	5/18/06	8:11p	5/19/06	11:40p	6500	2821	613	1240	-19	41psi	.75	.75	
5	5/19/06	11:40p	5/20/06	2:50a	8000	336	73	120	41psi	165psi	.75	.75	End Waterblock 247 treatment
Totals	5/20/06					7777	162	4000					

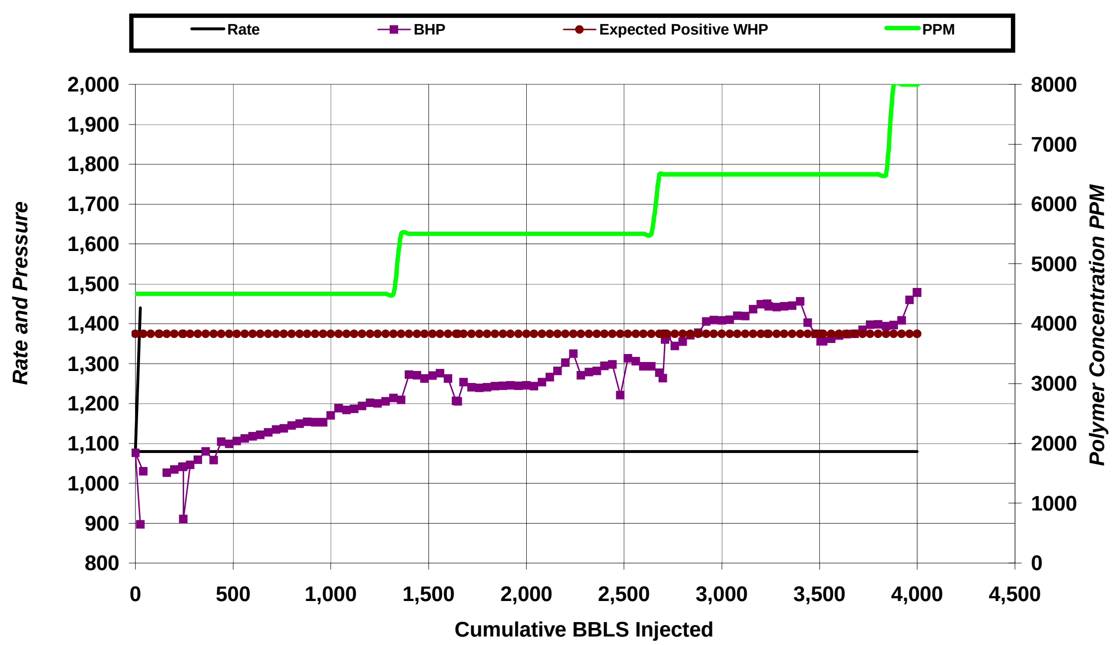


Figure 17: Injection rate, bottomhole pressure and polymer concentration during Hall B#4 gel treatment

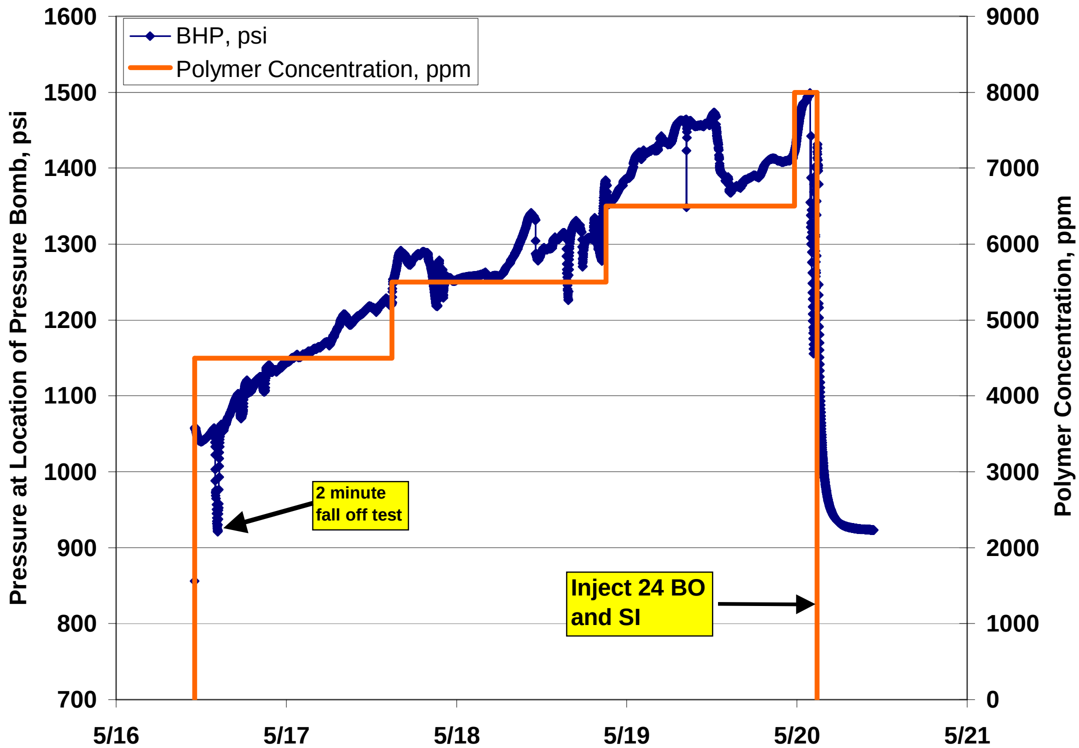
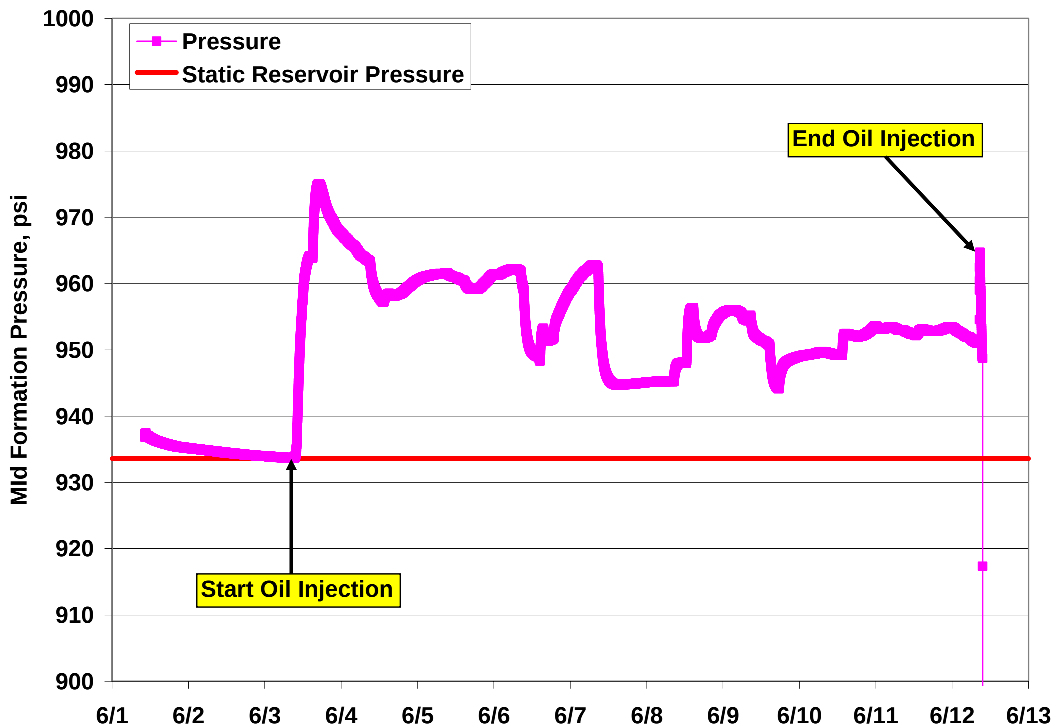


Figure 18: Bottomhole pressure and polymer concentration during gel treatment of Hall B #4



.

Figure 19: Mid formation pressure during oil injection to dehydrate gel.

Task 4 Post treatment dehydration of gel: Dehydration of the gel began on June 3 after 14 days shut-in following the gel treatment. About 102 barrels of oil were injected at an average rate of 11.33 B/D. Figure 19 shows the mid-formation pressure during oil injection. The downhole pressure tool was located at 3365 ft, so 19.6 psi was added to the measured pressure to obtain mid-formation pressure. Fluctuations of the pressure are due to the difficulty of maintaining low oil injection rates. Average BHP during oil injection was 955 psi, while the static BHP was 934 psi. Average pressure drop during oil injection was 21 psi indicating that there was little flow resistance to oil following the gel treatment. Effective permeability to oil during this period was estimated to be 318 md.

Task 5 Place well on production: The well was placed on production on June 13. Initial oil and water rates are shown on Figure 20.

Task 6 Analysis of Performance: Oil production rates are substantially less than expected and water rates are higher than expected. The volume of oil produced is about 231 bbls while the oil injected at the end of the treatment and during gel dehydration was 126 bbls leaving a net gain of 105 bbls after the treatment. The well is not pumped off and the fluid level is 46 joints above the pump. There was no reduction of water production from this treatment and no incremental oil production. The cause of this performance was not

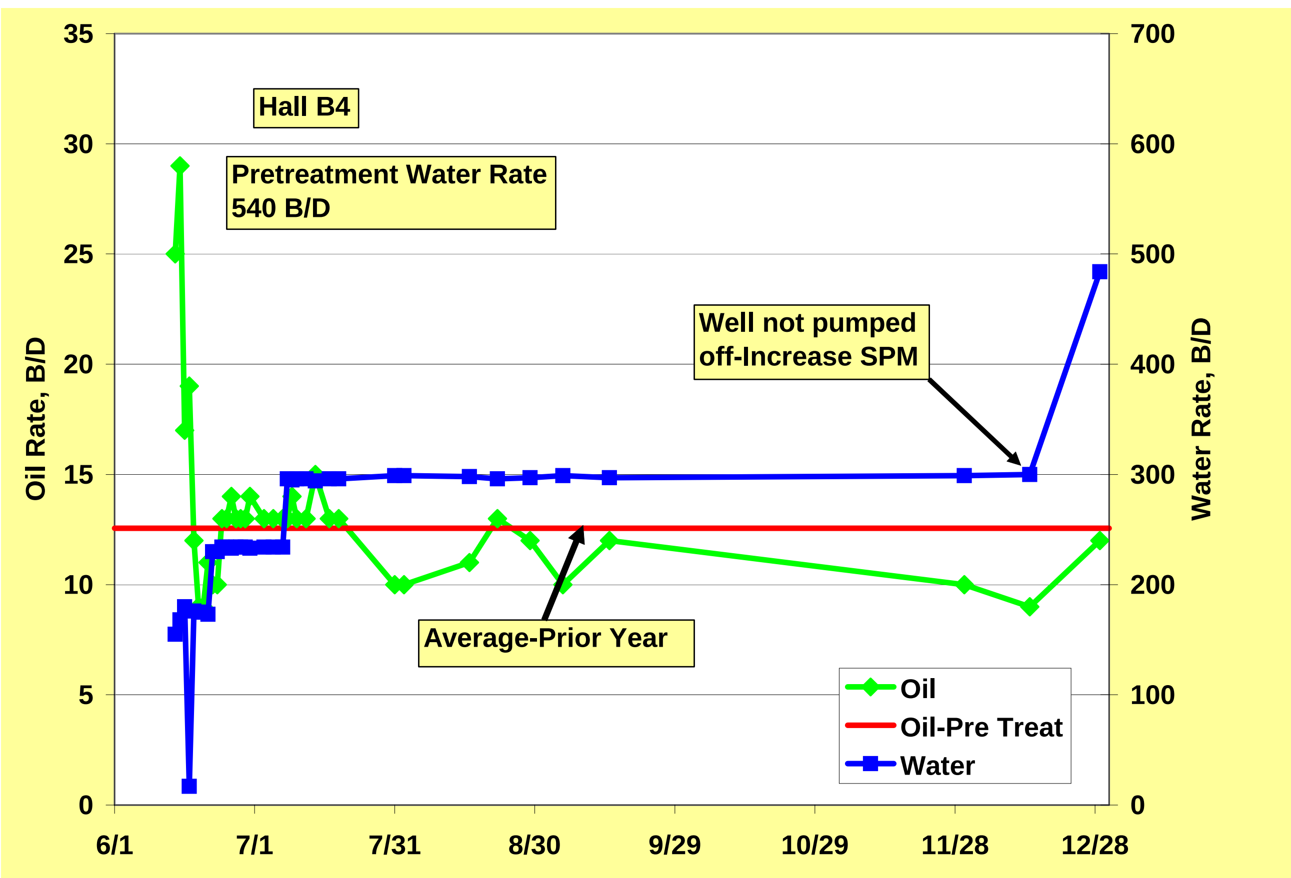


Figure 20: Oil and water production following gel treatment and dehydration of Hall B#4

identified. The well acted as if the gelant flowed through sections of the reservoir that were not associated with water production. The poor performance is not believed to be related to the DPR treatment.

Task 7 Participate in SWC and PTTC Workshops: Richard Pancake made a presentation at the Stripper Well Workshop in University Park, PA, October 17-18, 2005. A poster exhibit and presentation was prepared for the PTTC/Stripper Well Technology Transfer Workshop in Pittsburgh,PA , November 9, 2006. An exhibit was prepared for the Oklahoma Oil and Gas Trade Exhibition held in Oklahoma City on October 26, 2006 and the Kansas Oil and Gas Trade Show held in Great Bend in September 12, 2006.

CONCLUSIONS

1. Sustained reduction in water production was achieved in two of the three wells treated. Incremental oil was produced in two of the wells. One well did not respond to the gel treatment. In wells producing incremental oil, oil rates eventually declined to pretreatment rates or below pretreatment rates by a few months after treatment.
2. Results from the post treatment process of oil injection to dehydrate the gel after placement are inconclusive when compared to wells in which the gel was not dehydrated after placement. Two wells that received the designed gelant treatment have sustained reductions in water production over periods of 12-18 months after treatment. Both wells produced incremental oil. Production of incremental oil has ceased in Colahan A#28. The oil rate in McCord A#1 declined below the pretreatment value about five months after treatment.
3. The treatment of Hall B#4 was not successful, but is not believed to be related to the dehydration process
4. Dehydration of the gel after placement was done with relatively small pressure increases while injection of oil at rates of about 10 B/D. Low flow resistance was not expected and suggests that the effective resistance to flow developed after placement of the gelant is less than generally believed. Pressures increased observed during oil injection at rates of about 10 B/D in Arbuckle wells were less than 100 psi.
5. It is not necessary to measure bottomhole pressure during the dehydration process in Arbuckle reservoirs. The cost of measuring BHP is the main additional cost of dehydrating the gel after placement.
6. Chromium concentrations in the produced water were less than 1 ppm and declined with volume of water produced.
7. Polymer concentrations in the produced water were less than 250 ppm(as carbon) and declined with the volume of water produced.

REFERENCES: None